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Wet/Dry Cooling and Cooling Tower Blowdown Disposal in Synthetic Fuel and Steam-Electric Power Plants

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This report extends the results of a previous study dealing with the detailed determination of consumptive water use and wet-solids residuals for coal and oil shale conversion plants and coal-fired steam-electric power generation plants located in the Western United States. The present report addresses the problem of determining the degree to which wet cooling, dry cooling, or wet/dry cooling should be used as a function of the true cost of water. The economics of cooling gas compressor interstage coolers for coal conversion and cooling steam turbine condensers for coal conversion and steam-electric power generation are also examined. The report also includes results of a separate EPA/DOE study of 42 coal/oil shale conversion plantsite combinations to provide an enlarged data base for more meaningful regional water assessments. The costs of wastewater treatment and blowdown treatment and disposal are calculated for coal conversion and steam-electric power plants are also included.

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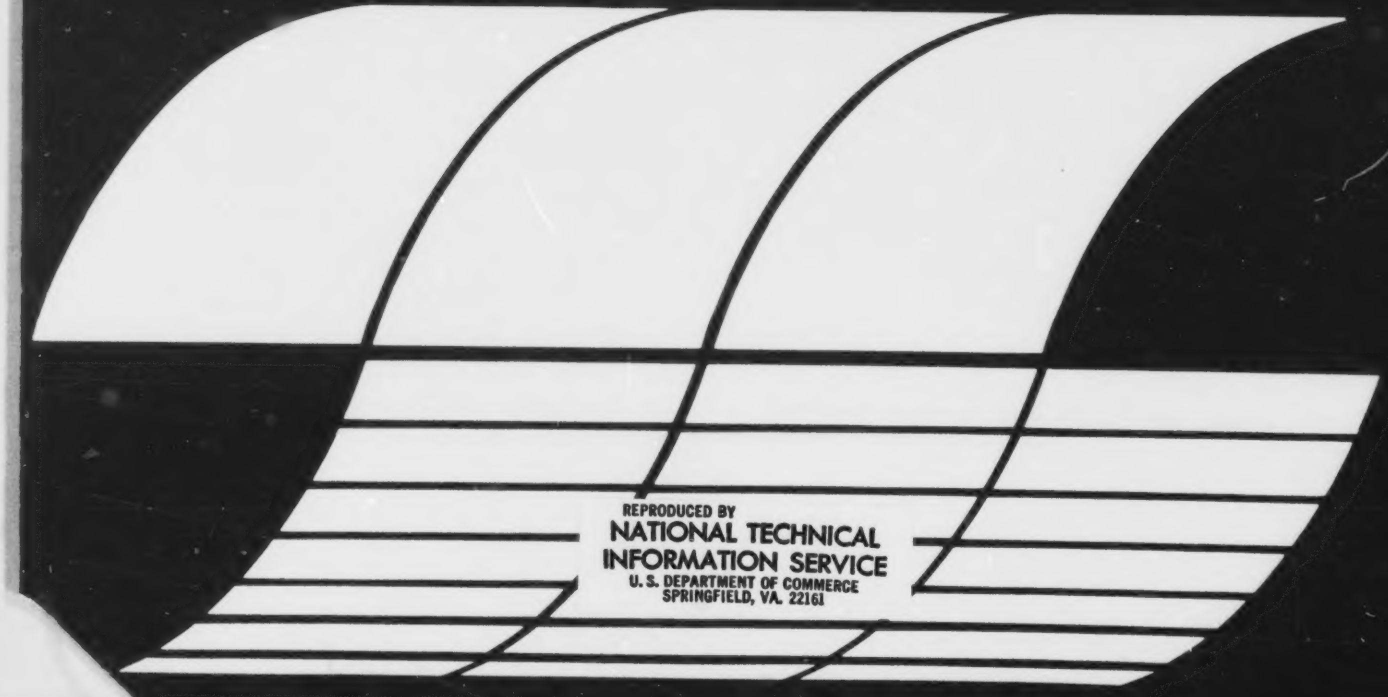

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March 1979

WET/DRY COOLING AND COOLING TOWER BLOWDOWN DISPOSAL IN SYNTHETIC FUEL AND STEAM-ELECTRIC POWER PLANTS

A Subcontract Report to the University of Oklahoma
Science and Public Policy Program for:

Technology Assessment of Western Energy Resource Developmen

EPA Contract Number 68-01-1916

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FOREWARD

The production of electricity and fossil fuels inevitably impacts Man and his environment. The nature of these impacts must be thoroughly understood if balanced judgements concerning future energy development in the United States are to be made. The Office of Energy, Minerals and Industry (OEMI), in its role as coordinator of the Federal Energy/Environment Research and Development Program, is responsible for producing the information on health and ecological effects - and methods for mitigating the adverse effects - that is critical to developing the Nation's environmental and energy policy. OEMI's Integrated Assessment Program combines the results of research projects within the Energy/Environment Program with research on the socioeconomic and political/institutional aspects of energy development, and conducts policy-oriented studies to identify the tradeoffs among alternative energy technologies, development patterns, and impact mitigation measures.

The Integrated Assessment Program has supported several "technology assessments" in fulfilling its mission. Assessments have been supported which explore the impact of future energy development on both a nationwide and a regional scale. Current assessments include national assessments of future development of the electric utility industry and of advanced coal technologies (such as fluidized bed combustion). Also, the Program is conducting assessments concerned with multiple-resource development in two "energy resource areas":

- Western coal states
- Lower Ohio River Basin

This report, which describes wet/dry cooling and cooling tower blowdown disposal in synthetic fuel and steam-electric power plants is the second of two major reports prepared by Water Purification Associates under Subcontract to the Science and Public Policy Program of the University of Oklahoma as a part of its "Technology Assessment of Western Energy Resource Development" study. The first report made a detailed determination of consumptive water use and wet-solids residuals for coal and oil shale concession plants and coal-fired steam-electric power plants. This report focuses on the problem of making a choice of cooling options on the basis of the true cost of water.

We would like to receive your comments concerning this report. Such comments will help us to improve the usefulness of the products produced by our Integrated Assessment Program.

Steven Reznek

Steven R. Reznek

Acting Deputy Assistant Administrator
for Energy, Minerals and Industry

ABSTRACT

This report extends the results of a previous study dealing with the detailed determination of consumptive water use and wet-solids residuals for coal and oil shale conversion plants and coal-fired steam-electric power generation plants located in the Western United States. The present report addresses the problem of determining the degree to which wet cooling, dry cooling, or wet/dry cooling should be used as a function of the true cost of water. The economics of cooling gas compressor interstage coolers for coal conversion and cooling steam turbine condensers for coal conversion and steam-electric power generation have been examined. The results show that for coal conversion plants located in the Western coal and oil shale bearing regions, it is economical to use a large degree of dry cooling for the steam turbine condensers and either wet or wet/dry cooling for the gas interstage coolers. For wet/dry cooling, the total water consumption in a coal conversion plant is 15 to 40 percent less than with a high degree of wet cooling. Because of the capital intensive nature of dry cooling, the penalty in going to a wet/dry cooling system is about 0.5 - 1.0¢/10^6 Btu of product output, if the cost of water is negligible.

The total water consumed by a steam-electric power plant using a wet/dry cooling system can be reduced by about 70 to 80 percent below that for all wet cooling of the steam turbine condensers. However, this is only economical if the cost of water exceeds about $3.50/1000 gals, which is not likely to be the case. If the cost of water is negligible, then the maximum cost penalty is about 1-2 mils/kw-hr. The use of wet/dry cooling in power plants will most likely be dictated by the local availability of water.

Two other subject areas are also covered in this report. First, results of a separate EPA/DOE study of 42 coal/oil shale conversion plant-site combinations are included to provide an enlarged data base for more meaningful regional water assessments. Second, the costs of wastewater treatment and blowdown treatment and disposal are calculated for coal conversion and steam-electric power plants.

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Conversion Factors

Conversion of American to International System (SI) Units

	Multiply	By	To Obtain
ACCELERATION	foot/second^2	3.048×10^{-1}	meter/second^2
	free fall, standard	9.807	meter/second^2
AREA	acre	4.047×10^{3}	meter^2
	feet^2	9.290×10^{-2}	meter^2
ENERGY	Btu (mean)	1.056×10^{3}	joule
	calorie (mean)	4.190	joule
	kilowatt-hours	3.60×10^{6}	joule
ENERGY/AREA-TIME	Btu/foot^2 hour	3.152×10^{-1}	watt/meter^2
	Btu/foot^2 minute	1.891×10^{2}	watt/meter^2
	Btu/foot^2 second	1.135×10^{4}	watt/meter^2
	calorie/cm^2 minute	6.973×10^{2}	watt/meter^2
FORCE	dyne	1.00×10^{-5}	newton
	kilogram force (Kg$_f$)	9.807	newton
	pound force (lb$_f$, avoirdupois)	4.448	newton
LENGTH	foot	3.048×10^{-1}	meter
	mile	1.609×10^{3}	meter
MASS	pound (avoirdupois)	4.536×10^{-1}	kilogram
	ton (metric)	1.00×10^{3}	kilogram
	ton (short, 2000 lb)	9.072×10^{2}	kilogram
MASS/TIME	pound/hour	1.260×10^{-4}	kilogram/second
	pound/minute	7.560×10^{-3}	kilogram/second
	ton (short)/hour	2.520×10^{-1}	kilogram/second
	ton (short)/day	1.050×10^{-2}	kilogram/second
MASS/VOLUME	gram/centimeter^3	1.00×10^{3}	kilogram/meter^3
	pound/foot^3	1.602×10^{1}	kilogram/meter^3
	pound/gallon (U.S. liquid)	1.198×10^{2}	kilogram/meter^3
MISCELLANEOUS	Btu/hr-ft^2-°F	5.674	joules/sec-m^2-°C
	Btu/kw-hr	2.929×10^{-1}	joules/kw-sec
	Btu/lb$_m$	2.324×10^{3}	joule/kg
	Btu/lb$_m$-°F	4.184×10^{3}	joule/kg-°C
	gal/10^6 Btu	3.585×10^{-12}	meter^3/joule
	kilocalorie/kilogram	4.184×10^{3}	joule/kg
POWER	Btu/hour	2.929×10^{-1}	watt
	Btu/minute	1.757×10^{1}	watt
	Btu/second	1.054×10^{3}	watt
	calorie/hour	1.162×10^{-3}	watt
	calorie/minute	6.973×10^{-2}	watt
	calorie/second	4.184	watt
	horsepower	7.457×10^{2}	watt
PRESSURE	atmosphere	1.013×10^{5}	pascal (= newton/m^2)
	foot of water (39.2°F)	2.989×10^{3}	pascal
	psi (lb$_f$/in^2)	6.895×10^{3}	pascal
	lb$_f$/foot^2	4.788×10^{1}	pascal
SPEED	foot/minute	5.08×10^{-3}	meter/second
	foot/second	3.048×10^{-1}	meter/second
	mile/hour	4.470×10^{-1}	meter/second
TEMPERATURE	°F	0.556 (°F + 459.7)	°K

(continued)

Conversion Factors (Continued)

	Multiply	By	To Obtain
VOLUME	acre foot	1.590×10^{-1}	meter^3
	barrel (oil, 42 gal)	1.233×10^{3}	meter^3
	foot^3	2.832×10^{-2}	meter^3
	gallon (U.S. liquid)	3.785×10^{-3}	meter^3
VOLUME/TIME	ft^3/min	4.719×10^{-4}	meter^3/second
	ft^3/sec	2.832×10^{-2}	meter^3/second
	gal (U.S. liquid)/day	4.381×10^{-8}	meter^3/second
	gal (U.S. liquid)/min	6.309×10^{-5}	meter^3/second

Other Conversion Factors

The following table is based on a density of water of 62.3 pounds per cubic foot. This is the density of water at 68°F (20°C) and corresponds to 8.33 pounds of water per gallon.

acres	4.36×10^{4}	square feet
acres	1.56×10^{-3}	square miles
acre-feet	4.36×10^{4}	cubic feet
acre-feet	3.26×10^{5}	gallons
acre-feet/year	1.38×10^{-3}	cubic feet/second
acre-feet/year	3.91×10^{-5}	cubic meters/second
acre-feet/year	6.20×10^{-1}	gallons/minute
acre-feet/year	8.93×10^{-4}	million gallons/day
barrels, oil	4.2×10	gallons
Btu	2.52×10^{2}	calories
Btu	3.93×10^{-4}	horsepower-hours
cubic feet	2.30×10^{-5}	acre-feet
cubic feet	7.48	gallons
cubic feet of water	6.23×10^{1}	pounds of water
cubic feet/second	4.49×10^{2}	gallons/minute
cubic feet/second	6.46×10^{-1}	million gallons/day
gallons	3.07×10^{-6}	acre-feet
gallons	2.38×10^{-2}	barrels, oil
gallons	1.34×10^{-1}	cubic feet
gallons of water	8.33	pounds of water
gallons/minute	1.61	acre-feet/year
gallons/minute	2.23×10^{-3}	cubic feet/second
gallons/minute	1.44×10^{-3}	million gallons/day
gallons of water/minute	5.00×10^{-1}	thousand pounds of water/hr
horsepower	6.11×10^{4}	Btu/day
horsepower	2.55×10^{3}	Btu/hour
kilowatt-hours	3.41×10^{3}	Btu
milligrams/liter	1	parts/million
million gallons/day	1.12×10^{3}	acre-feet/year
million gallons/day	1.55	cubic feet/second
million gallons/day	6.94×10^{2}	gallons/minute
million gallons of water/day	3.47×10^{2}	thousand pounds of water/hr
pounds of water	1.20×10^{-1}	gallons of water
pounds of water	1.60×10^{-2}	cubic feet of water
pound moles of gas	3.80×10^{2}	standard cubic feet of gas
square feet	2.30×10^{-5}	acres
temperature, °C	1.8	32 - °F
temperature, °F-32	5.56×10^{-1}	°C
thousand pounds/hour	1.2×10	tons/day
thousand pounds/hour	4.38×10^{3}	tons/year
thousand pounds of water/hour	2.00	gallons of water/minute
thousand pounds of water/hour	2.88×10^{-3}	millions gals of water/day
tons (short)	2×10^{3}	pounds
tons (short)	9.07×10^{-1}	metric tons
tons/day	8.33×10^{-2}	thousand pounds/hour
tons/year	2.28×10^{-4}	thousand pounds/hour
watts	3.41	Btu/hour

1. SUMMARY

1.1 INTRODUCTION

In a previous report[1] the water requirements of several fossil fuel energy conversion technologies were determined at six sites in the Western United States. The results of the study showed that the largest quantity of water consumed in all facilities, except oil shale, is the water evaporated for cooling. Calculations for steam electric power generation were based on all wet cooling of turbine condensers. However, a partial evaluation was made of wet/dry cooling which showed that a reduction of over 75 percent in water consumption could be achieved but with the economics depending on the cost of water. Calculations for the synthetic fuel plants were based on all wet cooling of turbine condensers and interstage coolers. Combination wet/dry cooling was not examined for the synthetic fuel plants, but could also reduce the cooling water requirements substantially. The cost of water when wet/dry cooling becomes economically viable was estimated but not quantified. The present report addresses the problem of determining the degree to which wet cooling, dry cooling or wet/dry cooling should be used as a function of the true cost of water.

The results presented in Reference 1 were also limited in two other respects. First, a total of only fourteen (14) coal and oil shale conversion plant-site combinations were studied with the total number of sites limited to six. The regional water impact assessments presented in Reference 2 were based on this limited data base. Results of a study of 42 plant-site combinations are included in this report to provide an enlarged data base for more meaningful regional water assessments.

Second, the costs of wastewater treatment in coal gasification plants were not calculated in Reference 1. In this report these costs are calculated together with the costs of blowdown treatment and disposal to determine if they are excessive with respect to the cost of the product fuel or the cost of electricity.

1.2 WET/DRY COOLING

The water consumed in cooling is a large percentage of the total water consumed in a plant converting coal to synthetic fuel. This is true even when all effluent water streams are recycled or reused within the mine or the plant after any necessary treatment. For example, for the four Synthane plants studied under the first phase of the program[1], the cooling water consumption ranged from 65 to 70 percent of the total water consumption, while for the four Synthoil plants the range was 71 to 86 percent. Coal-fired, steam-electric power plants even use a higher percentage of cooling water, ranging from 80 to 90 percent of the total water consumed for the six sites.

In coal conversion plants the heating value in the raw material not recovered in the synthetic fuel or the by-products must be transferred to the environment. Some of this unrecovered heat is lost directly to the atmosphere, leaving the plant in hot gases up a flue, in water vapor from coal drying and in other direct ways. However, the largest fraction of the unrecovered heat is indirectly transferred to the atmosphere, through either air (dry) cooling or wet cooling or a combination of the two. A high degree of wet cooling was assumed in calculating the water requirements for the Synthane and Synthoil processes studied in Reference 1. High wet cooling does not mean that all of the unrecovered heat is dissipated by wet cooling. In the Synthane process, it was calculated that the amount of unrecovered heat dissipated by wet cooling was 42 percent, while for the Synthoil process wet cooling ranged from 48 to 55 percent. Thus, even for a high degree of wet cooling, more than 50 percent of the unrecovered heat is economically dissipated to the atmosphere.

The degree to which wet cooling or dry cooling is used is an economic one depending on the cost of water. The economics must be calculated for each type of cooling load in the plant. We assumed in the calculations presented in Reference 1 that intermediate and product gas and liquid process streams are dry cooled to 140°F and wet cooled below this temperature, that the gas purification regenerator condenser is dry or wet/dry cooled dependent on the choice of purification system, that off-gas scrubbing and quenching is dry cooled, and that both the condensers for steam turbines and the gas compressor interstage coolers are wet cooled. In this report, the economics of the last two cooling loads are examined for coal conversion plants.

For steam turbine condensers in a coal conversion plant, when water costs more than about 25¢/1000 gals, combined wet/dry cooling should be used and the water consumption will be less than 10 percent of the consumption with all wet cooling. This summary is based on calculations performed for Farmington, New Mexico, Casper, Wyoming and Beulah, North Dakota for a range of amortization and maintenance charges and electrical energy and steam costs.

Results on interstage cooling of an air compressor in a coal conversion plant show that if the cost of water exceeds about $1.50 per 1000 gals, series wet/dry interstage coolers should be used with water consumption 50 to 60 percent of the consumption for all wet coolers. Dry cooling is preferred for all unit cost sets studied at all sites for interstage cooling of a hydrogen compressor.

Three cooling options have been considered, each option denoted by the different degrees of wet cooling used for turbine condensers and interstage coolers on gas compressors in coal conversion plants. At a site where water is plentiful and inexpensive to transport, high wet cooling would be used. The cooling loads on both the turbine condensers and interstage coolers are taken to be all wet cooled. For the Lurgi process, a detailed thermal balance is not available and wet cooling is assumed to be used to dispose of 42 percent of the total unrecovered heat. This value is the same one estimated for the Synthane process. In regions where water is marginally available or moderately expensive to transport, intermediate wet cooling would be used. This assumes that wet cooling handles 10 percent of the cooling load on the turbine condensers and all of the load of the interstage coolers. For the Lurgi process it is assumed that 28 percent of the unrecovered heat is dissipated by wet cooling, which is in the range of values found in the proposed El Paso and Wesco Lurgi designs and the same one estimated for the Synthane process. The oil shale processes are taken to correspond to intermediate cooling. Twenty-eight percent of the unrecovered heat is dissipated by wet cooling for the Paraho Direct process, while 18-19 percent is dissipated for both the Paraho Indirect and TOSCO II processes. In regions where water is expensive to transport or scarce, minimum practical wet cooling is assumed with wet cooling handling 10 percent of the cooling load on the turbine condensers and 50 percent of the load on the interstage coolers. For this case we have assumed the Lurgi process dissipates about 24 percent of the unrecovered heat by wet cooling.

If water costs more than about $1.50/1000 gals, minimum practical cooling would be used. Intermediate cooling would be used if water costs between $0.25 to $1.50/1000 gals, while high wet cooling would be used if water costs less than $0.25/1000 gals.

Table 1-1 shows the total net water consumed for all three cooling options in coal conversion plants located at the study sites. The results presented in Phase I of the program are indicated by an asterisk. It should be noted that the results for Lurgi presented in Reference 1 correspond to the case of intermediate wet cooling, as we have defined it above. For the Lurgi process the total water consumed in the case of intermediate wet cooling is 21 to 32 percent less than the case of high wet cooling. The water consumption with minimum practical wet cooling is 27 to 42 percent less than with high wet cooling. For Synthane the reductions are 23-24 percent and 27-29 percent, while for Synthoil the reductions are 16-19 percent and 21-25 percent, respectively. The largest reduction is between high wet cooling and intermediate wet cooling, while there is only an additional reduction of about 2 to 5 percent between intermediate wet cooling and minimum practical cooling.

Table 1-1 shows that the reduction in the net water consumed between high wet cooling and minimum practical wet cooling is about 9 gal/10^6 Btu for the Lurgi and Synthane processes and 4 gal/10^6 Btu for the Synthoil process. However, a penalty must be paid in going to a wet/dry cooling system because of the capital intensive nature of dry cooling. The penalty is about 1¢/10^6 Btu for the Lurgi and Synthane processes and about 0.5¢/10^6 Btu for the Synthoil process. This penalty is the maximum penalty and assumes that the cost of water is negligible. The price of pipeline gas is estimated to be about $3.00-$4.00/ 10^6 Btu.

The results presented in Reference 1 for oil shale have been extended from the TOSCO II indirect retorting process to include the Paraho Direct and Indirect processes. Underground mining and surface retorting are assumed for

TABLE 1-1 NET WATER CONSUMED AT EACH SITE FOR COAL CONVERSION

		High Wet Cooling		
	Beulah North Dakota	Colstrip Montana	Gillette Wyoming	Navajo/ Farmington New Mexico
LURGI (250 x 10^6 scf/stream day)				
acre-ft/yr	4,891	6,283	5,823	7,128
gal/cal min+	3,032	3,895	3,661	4,419
gal/10^6 Btu	20.2	26.0	24.4	29.4
SYNTHANE (250 x 10^6 scf/stream day)				
acre-ft/yr	7,671*	7,808*	7,776*	8,670*
gal/cal min+	4,756*	4,841*	4,821*	5,375*
gal/10^6 Btu	31.7	32.3	32.1	35.8
SYNTHOIL (100,000 bbl/stream day)				
acre-ft/yr	10,085*	10,296*	9,227*	11,753*
gal/cal min+	6,253*	6,383*	5,721*	7,130*
gal/10^6 Btu	16.1	16.5	14.8	18.4

+gallons per calendar minute, 90% load factor
*Phase I results reported in Ref. 1

TABLE 1-1(continued)

		Intermediate Wet Cooling		
	Beulah North Dakota	Colstrip Montana	Gillette Wyoming	Navajo/ Farmington New Mexico
LURGI (250 x 10^6 scf/stream day)				
acre-ft/yr	3,307*	4,618*	4,206*	5,639*
gal/cal min$^+$	2,050*	2,863*	2,608*	3,496*
gal/10^6 Btu	13.7	19.1	17.4	23.3
% of high wet cooling	68	74	71	79
SYNTHANE (250 x 10^6 scf/stream day)				
acre-ft/yr	5,878	5,923	5,875	6,694
gal/cal min$^+$	3,644	3,672	3,642	4,155
gal/10^6 Btu	24.3	24.5	24.3	27.7
% of high wet cooling	77	76	76	77
SYNTHOIL (100,000 bbl/stream day)				
acre-ft/yr	8,170	8,481	7,539	9,655
gal/cal min$^+$	5,065	5,258	4,674	5,986
gal/10^6 Btu	13.1	13.6	12.1	15.4
% of high wet cooling	81	82	82	84

+gallons per calendar minute, 90% load factor

*Phase I results reported in Ref. 1

TABLE 1-1 (concluded)

		Minimum Practical Wet Cooling		
	Beulah North Dakota	Colstrip Montana	Gillette Wyoming	Navajo/ Farmington New Mexico
LURGI (250 x 10^6 scf/stream day)				
acre-ft/yr	2,853	4,142	3,721	5,213
gal/ cal min$^+$	1,769	2,568	2,307	3,232
gal/10^6 Btu	11.8	17.1	15.1	21.5
% of high wet cooling	58	66	63	73
SYNTHANE (250 x 10^6 scf/stream day)				
acre-ft/yr	5,520	5,536	5,484	6,289
gal/ cal min$^+$	3,422	3,432	3,400	3,899
gal/10^6 Btu	22.8	22.9	22.7	26.0
% of high wet cooling	72	71	71	73
SYNTHOIL (100,000 bbl/stream day)				
acre-ft/yr	7,552	7,904	7,026	9,112
gal/ cal min$^+$	4,682	4,900	4,356	5,649
gal/10^6 Btu	12.1	12.6	11.2	14.6
% of high wet cooling	75	77	76	79

+gallons per calendar minute, 90% load factor all oil shale processes. These results are shown in Table 1-2 for both the net water consumed and solid residuals generated. The calculations for the TOSCO II process have been refined and are also shown on Table 1-2.

In general the net water requirements normalized with respect to the product output are largest for coal gasification followed in turn by coal liquefaction. For intermediate wet cooling the water requirements for the Paraho Direct process are comparable with the Synthoil process, which roughly produces the same product. However, the Paraho Indirect and TOSCO II processes have the largest net water requirements due mainly to the larger requirements for spent shale disposal and revegetation.

For steam-electric power generation, wet/dry cooling was examined for Navajo/Farmington, New Mexico and Beulah, North Dakota. The optimum costs for New Mexico were slightly higher than those at North Dakota, generally not exceeding 10 percent. The point at which the cost of the wet/dry cooling system is optimum occurs when the evaporation rate is approximately 15 percent of the evaporation rate for all wet cooling. This optimum point is the same at both sites and the result was extended to include all six study sites.

Table 1-3 shows the total water consumed for all wet cooling and the optimum wet/dry cooling system for steam electric power generation. The estimates for all wet cooling represent consumptive water use for well managed power plants in the Western and Southwestern regions of the country. A reduction of 85% in the cooling water requirements reduces the total water consumed by a plant by 68-75 percent. However, the changeover water costs, i.e. the cost of water above which wet/dry cooling would be used, range from $3.65 to $5.87 per 1000 gals evaporated for power generation plants, much higher values than those for coal conversion plants producing synthetic fuels. The busbar energy cost penalty in using wet/dry cooling instead of all wet cooling ranges from 1.4 mils/kw-hr to 1.97 mils/kw-hr for Navajo, New Mexico and 1.2 mils/kw-hr to 1.9 mils/kw-hr for Beulah, North Dakota, compared to the cost of electricity of 20 to 30 mils/kw-hr.

In the site studies discussed in Section 1.3, on a purely economic basis either intermediate cooling or minimum practical cooling is desirable for most of the Western sites for coal or oil shale conversion. For steam-electric power plants, if only the costs of water are considered, then all wet cooling would be desired, since wet/dry cooling is so capital

TABLE 1-2 NET WATER CONSUMED AND WET-SOLID RESIDUALS GENERATED FOR OIL SHALE CONVERSION

	Intermediate Cooling Rifle, Colorado
PARAHO DIRECT (100,000 bbl/stream day)	
Net water consumed	
acre ft/yr	5,771
gal/stream min[+]	3,578
gal/10^6 Btu	18
Wet-solid residuals	
tons/day	75,000
lb/10^6 Btu	520
PARAHO INDIRECT (100,000 bbl/stream day)	
Net water consumed	
acre ft/yr	9,233
gal/stream min[+]	5,724
gal/10^6 Btu	28
Wet-solid residuals	
tons/day	90,000
lb/10^6 Btu	620
TOSCO II (100,000 bbl/stream day)	
Net water consumed	
acre ft/yr	9,307*
gal/stream min[+]	5,770*
gal/10^6 Btu	29*
Wet-solid residuals	
tons/day	60,000
lb/10^6 Btu	470

[+] gallons per calendar minute, 90% load factor

*Modified from Phase I calculations (see Ref. 1)

TABLE 1-3 NET WATER CONSUMED AT EACH SITE FOR STEAM-ELECTRIC POWER GENERATION

	All Wet Cooling++		Wet/Dry Cooling		%
	acre-ft/yr	gal/stream min	acre-ft/yr	gal/stream min	all wet
Beulah, North Dakota*	23,884	14,807	5,494	3,406	23
Colstrip, Montana*	26,659	16,527	7,336	4,548	28
Gillette, Wyoming*	25,842	16,021	6,465	4,008	25
Kaiparowitz/Escalante, Utah*	29,816	18,483	9,481	5,878	33
Navajo/Framington, New Mexico*	29,206	18,106	9,089	5,635	31
Rifle, Colorado+	9,494	5,885	2,786	1,727	29

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*3,000 MWe @ 35% eff. and 70% load factor
+1,000 MWe @ 35% eff. and 70% load factor
++Phase I results reported in Ref. 1.

intensive. and the fuel penalty is so high. However, if water is in short supply, or if there are other pressures for conserving water, then it is obvious that wet/dry cooling is feasible.

1.3 REGIONAL WATER REQUIREMENTS AND RESIDUALS DISPOSAL

A study[3] was recently completed by Water Purification Associates under the sponsorship of the U.S. Environmental Protection Agency and the Department of Energy, in which 42 coal and oil shale conversion plant-site combinations were studied in the Western states. In order to extend the data base of the present study, these results are included to provide more meaningful regional water impact assessments.

Estimates were made of the cost of transporting water to all of the plant-sites for two limiting cases: low water demand and high water demand. Low water demand corresponds to a synthetic fuel production rate of approximately 1.0×10^6 barrels/day of synthetic crude, or its equivalent in other fuels of 5.8×10^{12} Btu/day, while high water demand corresponds to a synthetic fuel production rate of approximately 4.0×10^6 barrels/day of synthetic crude, or its equivalent in other fuels of 23.2×10^{12} Btu/day. For low water demand two standard size coal or oil shale conversion plants were assumed to be located in each of eleven hydrologic regions in the Western states for a total of 22 plants producing approximately 1.0×10^6 barrels/day of synthetic crude. For high water demand 1×10^6 barrels/day of synthetic crude, or its equivalent in other fuels of 5.8×10^{12} Btu/day, were produced in each of three principal coal bearing regions and one oil shale region. Except for plants located near the mainstem of major rivers or near large reservoirs, the water transport cost estimates show that intermediate or minimum practical wet cooling would be desirable for most of the sites for low water demand. For high water demand, it is more economical to build a large pipeline to supply water to a large number of plants than to have a large number of individual pipelines supplying individual plants. The estimates show that except for large scale development near the mainstem of major rivers, intermediate cooling would be preferred for most of the sites.

Except for the Synthane process, the results of the limited six site-specific studies with respect to water consumption are in general agreement with the results of the more expanded site studies. For Synthane, the major difference is in the degree to which wet cooling was used to dissipate the unrecovered heat. In Reference 3 a more detailed thermal balance was made resulting in a reduction in the net water consumed of about 7 gals/10^6 Btu below those of Reference 1. The calculations of the total wet solid residuals reported in Reference 3 are about twice those reported in Reference 1, due primarily to the much larger quantities of flue gas desulfurization sludge and water treatment sludge.

Within a given coal region and for a given process, rank of coal and wet cooling option, differences in the net water consumed from site to site are not significant. However, within a given region there might be large variations in water availability and water costs and different cooling options at different sites will produce large differences in the cooling water consumed and the plant water requirements. Thus, for a particular process and coal rank, the cost of water and the particular cooling technology selected for a given plant are the main factors which determine the water use. Intermediate and minimum practical wet cooling should be used at most of the sites.

1.4 ECONOMICS OF WATER TREATMENT AND COOLING TOWER BLOWDOWN TREATMENT AND DISPOSAL

Estimates were made of the costs of treating water in a coal gasification plant for the purpose of recycling and reusing the water for in-plant uses to minimize the problem of disposal of contaminated waste streams. The main components of any water treatment plant include: boiler feed water treatment, process water or condensate cleanup, and cooling water treatment. Boiler feed water treatment includes primarily ion exchange. The foul condensate wastewater is assumed to be treated and blended with water from the river or used by itself as makeup to the cooling tower. The foul condensate treatment includes phenol extraction, ammonia separation and biological treatment. Cooling water treatment includes chemical addition and filtration.

The water treatment costs range from about 8¢/10^6 Btu product energy output to 12¢/10^6 Btu, while the energy requirements for water treatment range from about 4 to 6.5 percent of the product output. The cost of the product fuel will probably be in the range of \$3-4/10^6 Btu, so that the water treatment costs, after taking credit for the sale of by-product ammonia, will not exceed 5 percent of the sale of the product fuel.

The total costs and energy requirements for water treatment are primarily dependent on the costs and energy requirement for process condensate treatment. The costs of cooling water treatment comprise the lowest costs while boiler feed water treatment costs are intermediate between the two. The total costs and energy requirements for water treatment are not very sensitive to the choice of the cooling option with the costs not varying by more than 10 percent between a high degree of net cooling and minimum practical cooling.

The costs of the treatment and disposal of cooling tower blowdown were estimates for the case of zero discharge and the case of effluent discharge to the receiving water, for coal gasification and electric power generation. For each case the cooling tower was operated at either very few cycles of concentration (N = 2.5 cycles of concentration) or at very high cycles of concentration (N = 10). At low cycles of concentration, only chemical treatment of the circulating cooling water was assumed necessary. At high cycles of concentration, sidestream softening in a reactor-clarifier was assumed. Blowdown treatment included treatment by either electrodialysis or vapor compression, followed by disposal of the brine to the receiving water or to lined evaporation ponds. In some cases the product water from the electrodialysis or vapor compression unit was recycled back to the plant with credit taken for the product water.

For all cases the annual operating and amortization costs decreases as the cycles of concentration in the cooling tower increases. The costs are lower for Lurgi than for Synthane for all cases. The lowest costs are for those cases where there is no limitation on the method of disposing of the blowdown. This occurs when the blowdown is discharged directly to the receiving water or where the blowdown is disposed of with coal ash. The cost of blowdown treatment and disposal are in the range of approximately 0.40¢/10^6 Btu to 0.80¢/10^6 Btu for N = 2.5, and 0.20¢/10^6Btu to 0.35¢/10^6 Btu for N = 10 for coal gasification; and about 0.40 mils/kw-hr for N = 2.5 and 0.15 mils/kw-hr for N = 10 for steam-electric generation. As a basis for comparison, pipeline gas is expected to cost about \$3-4/10^6 Btu and electricity costs about 20 to 30 mils/kw-hr.

The cost of treatment and disposal of the blowdown increases if TDS (total dissolved solids) reduction is required for discharge to the receiving water. If a single stage electrodialysis system is used to reduce the TDS by

50 percent, then the costs increase to 1.25-2.75¢/10^6 Btu for N = 2.5 and 0.35-0.70¢/10^6 Btu for N = 10 for coal gasification; and to 1.35-1.60 mils/kw-hr for N = 2.5 and 0.30-0.40 mils/kw-hr for power generation.

The costs increase further for zero discharge. Three cases were considered with final disposal of the concentrated brine taking place in lined evaporation ponds. Of the three cases the least expensive was for blowdown treatment by 3-stage electrodialysis and recycle of the product water back to the plant for in-plant uses. The costs for this case range from 1.40-2.70¢/10^6 Btu for N = 2.5 and 0.40-0.70¢/10^6 Btu for N = 10 for coal gasification; and 1.50-1.70 mils/kw-hr for N = 2.5 and 0.40 mils/kw-hr for N = 10 for power generation. If credit is taken for the recycled water, then the costs are 0.65-1.05¢/10^6 Btu (N = 2.5) and 0.30 - 0.35¢/10^6 Btu (N = 10) for coal gasification; and 0.70-1.05 mils/kw-hr (N = 2.5) and 0.20-0.30 mils/kw-hr (N = 10) for power generation.

The costs for a vapor compression brine concentrator were the next expensive, ranging from 6.50-12.30¢/10^6 Btu (N = 2.5) and 1.20-2.30¢/10^6 Btu (N = 10) for coal gasification; and 6.90-7.30 mils/kw-hr (N = 2.5) and 1.20-1.40 mils/kw-hr (N = 10) for power generation. If credit is taken for recycle, then these costs would be reduced by approximately 0.80-1.50¢/10^6 Btu (N = 2.5) and 0.15-0.30¢/10^6 Btu (N = 10) for coal gasification; and by 0.70-0.80 mils/kw-hr (N = 2.5) and 10 mils/kw-hr (N = 10) for power generation.

The most expensive case was for complete blowdown disposal into lined evaporation ponds without blowdown treatment. The costs are 4.80-14.0¢/10^6 Btu (N = 2.5) and 0.90-2.50¢/10^6 Btu (N = 10) for coal gasification; and 6.00-9.50 mils/kw-hr (N = 2.5) and 1.10-1.60 mils/kw-hr (N = 10) for power generation.

REFERENCES (Section 1)

1. Gold, H., et al, "Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," EPA Report No. 600/7-77-037, Environmental Protection Agency, Washington, D. C., April 1977.

2. Science and Public Policy Program, University of Oklahoma, "Energy from the West: A Progress Report of a Technology Assessment of Western Energy Resource Development," EPA Report No. 600/7-77-072, Environmental Protection Agency, Washington, D. C., July 1977.

3. Gold, H. and Goldstein, D.J., "Water Related Environmental Effects in Fuel Conversion: Summary Volume and Appendix Volume," Environmental Protection Agency, Research Triangle Park, N.C., EPA Report No. 600/7-78-197a,b, October 1978.

2. SELECTED ASPECTS OF WET/DRY COOLING

2.1 INTRODUCTION AND CONCLUSIONS

2.1.1 Introduction

Evaporation for cooling can be a major consumptive use of water in coal conversion and generating plants[1]. In coal conversion plants, the heating value in the raw material not recovered in the synthetic fuel or the byproducts must be transferred to the environment. Some of this unrecovered heat is lost directly to the atmosphere, leaving the plant in hot gases up a flue, in water vapor from coal drying, in convective and radiant losses from machinery and container surfaces, and in other direct ways. However, the largest fraction of the unrecovered heat is indirectly transferred to the atmosphere. The heat to be dissipated may be transferred through a heat transfer surface that is cooled by air. This is called dry cooling, or air cooling, and negligible water consumption is incurred in this method. Alternatively, the heat transfer surface may be cooled by circulating water, which is itself cooled in a cooling tower with evaporation to the atmosphere of a fraction of the water. This is called wet cooling, or evaporative cooling. We are concerned in this section with these two methods of cooling or their use in combination, termed wet/dry cooling.

Under the same conditions an air cooled heat exchanger transfers less heat per unit area than a water cooled exchanger. Therefore, to transfer a given amount of heat, air cooling requires a larger surface area. Air coolers thus have a higher capital cost. Moreover, an air cooled system cannot usually reach temperatures as low as those in a water cooled system and, hence, the efficiency of conversion will be lower if air cooling is used to any great extent.

Wet cooling is less capital intensive and, in general, is less expensive to operate than dry cooling. Wet cooling, however, does require water, and water is not free. To move one thousand gallons of water one mile through a horizontal pipeline costs one to two cents. To treat water in a circulating cooling system and to dispose of the residues can cost $0.50 to $1.00 per thousand gallons of water evaporated[2]. The economic decision of whether to use wet or dry cooling, or a combination, at any given point of cooling in the plant depends on the true cost of water. This must include any costs to buy water rights and to transport the water to the plants, as well as the cost to treat the circulating cooling water and to dispose of the cooling tower residues.

The economics must be calculated for each type of cooling load in the plant. Major cooling loads have been classified[3], and Table 2-1 (taken from Reference 3) shows the classification for a typical substitute natural gas plant. More generally, types of cooling loads can be classified with the choice of wet or dry cooling as:

Cooling of intermediate and product gas and liquid process streams.	Dry cooling to 140°F and wet cooling below this temperature.
Gas purification regenerator condenser.	Dry or wet/dry, dependent on choice of purification system.
Off-gas scrubbing and quenching.	Dry.
Condensers for steam turbines.	Evaluated here.
Gas compressor interstage coolers.	Evaluated here.

In the above list the cooling method has been assigned to the first three classifications for reasons given in detail in References 2 and 3. In steam generating plants the principal cooling load is for steam turbine condensers. In a previous study[1], steam turbine condensers and gas compressor interstage coolers for coal conversion plants were assumed to be all wet cooled, while a partial evaluation was made of the wet/dry cooling of steam turbine condensers for power generating plants. Condensers for steam turbines in coal conversion and in generating plants are one of the subjects of this study. Gas compressor interstage coolers in coal conversion plants is the other subject. In a study just completed[4], detailed calculational procedures were presented for the cooling of steam turbine condensers and air compressor interstage coolers and calculations

TABLE 2-1. SUMMARY OF THE CHOICE OF WET OR DRY COOLING AND APPROXIMATE AMOUNT OF EVAPORATED WATER FOR AN SNG PLANT PRODUCING 250 x 10^6 SCF/DAY IN NEW MEXICO AND WYOMING

Point	Load (10^9 Btu/hr)	Breakeven Evaporated Water Cost (\$/10^3 gal)	Wet or Dry	Evaporated Water N.M. (10^6 gal/day)	Evaporated Water W.Y.O. (10^6 gal/day)
Gas purification (hot potassium carbonate) Regenerator condenser	1.3	0.46	Dry		
Pump drive	0.15		Wet	0.39	0.33
Off-gas scrubbing & quenching	1.1	zero	Dry		
Boiler steam generation	0.4	no cooling			
Oxygen production					
Air compressor intercoolers	0.2	9.4	Wet	0.53	0.45
Oxygen compressor intercoolers	0.1	3.3	Wet	0.26	0.22
Turbine condensers	0.6	2.6	Wet	1.57	1.33
Electric power generation					
Turbine condensers	0.12		Wet	0.31	0.27
Electricity	0.02	no cooling			
Coal drying (lignite)	0.5	no cooling			
Product cooling & drying	0.14	zero	85% Dry		
			14% Wet	0.05	0.04
TOTALS	4.67			3.11	2.64

From Reference 3

carried out for Farmington, New Mexico, Casper, Wyoming and some eastern sites and for a given set of unit costs. The procedures are also discussed in this report and the calculations extended to include Beulah, North Dakota and other sets of unit costs. Calculations are also presented for hydrogen compressor interstage coolers at the three western sites. The technical discussion and the results of the calculations will be found in the four following subsections. Economic calculations and our conclusions are given next.

2.1.2 Economics of Cooling Turbine Condensers in Coal Conversion Plants

Unit costs are shown on Table 2-2. Set number 1 is the base set; the other two sets show variations. There are three types of unit costs. The capital costs are for a 1980 start, which means that they are 1977 equipment costs with erection spread over the next two years. The capital costs will increase with time. More importantly, the capital costs do not change uniformly, so the relationship between capital costs of dry coolers and capital costs of cooling towers and wet coolers changes. We are not able to predict these changes, and no variations in capital costs have been considered.

The amortization and maintenance rates shown for set number 1 are reasonable for commercial enterprises today. Lower values are used in set number 3 to illustrate the effect of possible lower interest rates for utilities.

The energy costs shown for set number 1 are reasonable for today, and quite low. Energy costs, double those used in set number 1, are used in set number 2.

Using the unit costs and the summary of calculated results for wet/dry condenser cooling from Section 2.2, annual average costs, tabulated on Table 2-3, were calculated according to the following examples:

Dry condenser cost (¢/kw-hr) = (area, ft^2/kw)(cost, ¢/ft^2)(%/yr)(1/7000 hrs/yr)

Electrical energy (¢/kw-hr) = (energy, kw-hr/kw-hr)(cost, ¢/kw-hr)

Fuel penalty (¢/kw-hr) = (fuel penalty, Btu/kw-hr)(steam, ¢/Btu)

Note that "total costs" (¢/kw-hr) refers only to those costs dependent on the choice of the cooling system. Other components of production cost are not included.

For set number 1, various water costs were assumed and the results are shown graphically on Figures 2-1 to 2-4. The summary graph in Figure 2-4

TABLE 2-2. UNIT COSTS

SET NUMBER 1

	Cost	Pressure (p,psig)	Annual Charges for Amortization Plus Maintenance
Condensers and heat exchanger:			
Dry cooling	$\$22/\text{ft}^{2*}$	--	17%/yr
Wet cooling	$\$11.0/\text{ft}^2$	$p < 300$	20%/yr
	$\$12.1/\text{ft}^2$	$300 \leq p < 450$	
	$\$13.2/\text{ft}^2$	$450 \leq p < 600$	
	$\$19.2/\text{ft}^2$	$p \geq 600$	
Other:			
Cooling tower	$\$20$/gpm circulated		15%/yr
Electrical energy	2¢/kw-hr		
Steam	$\$1.80/10^6$ Btu		

SET NUMBER 2

As Set Number 1, but

	Cost
Electrical energy	4¢/kw-hr
Steam	$\$3.60/10^6$ Btu

SET NUMBER 3

As Set Number 1, but

	Annual Charges for Amortization Plus Maintenance
Dry cooled heat exchangers	13%/yr
Wet cooled heat exchangers	16%/yr
Cooling towers	11%/yr

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*Based on bare tube area of finned tubes.

TABLE 2-3. ANNUAL AVERAGE COSTS FOR WET/DRY CONDENSER COOLING

UNIT COSTS - SET NO. 1

Farmington, New Mexico

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.156	0.123	0.082	0.041	0
Wet condenser cost ¢/kw-hr	0.0031	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.024	0.032	0.046	0.054	0.046
Fuel penalty ¢/kw-hr	0	0	0.0008	0.0075	0.0285
Cooling tower ¢/kw-hr	0.0015	0.0075	0.015	0.022	0.030
Total ¢/kw-hr	0.185	0.179	0.175	0.172	0.167
Avg water consumption gal/kw-hr	0	0.014	0.101	0.374	0.707

Casper, Wyoming

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.148	0.117	0.078	0.039	0
Wet condenser cost ¢/kw-hr	0.0031	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.020	0.028	0.042	0.054	0.046
Fuel penalty ¢/kw-hr	0	0	0	0.0064	0.035
Cooling tower ¢/kw-hr	0.0015	0.0075	0.015	0.022	0.030
Total ¢/kw-hr	0.173	0.168	0.166	0.169	0.174
Avg water consumption gal/kw-hr	0	0.008	0.088	0.362	0.701

Beulah, North Dakota

Fraction designed dry	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.139	0.092	0.046	0
Wet condenser cost ¢/kw-hr	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.024	0.036	0.056	0.044
Fuel penalty ¢/kw-hr	0	0	0.002	0.025
Cooling tower ¢/kw-hr	0.007	0.015	0.022	0.030
Total ¢/kw-hr	0.185	0.175	0.174	0.162
Avg water consumption gal/kw-hr	0	0.058	0.265	0.671

TABLE 2-3. (continued)

UNIT COSTS - SET NO. 2

Farmington, New Mexico

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.156	0.123	0.082	0.040	0
Wet condenser cost ¢/kw-hr	0.0031	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.048	0.064	0.092	0.108	0.092
Fuel penalty ¢/kw-hr	0	0	0.0016	0.0015	0.057
Cooling tower ¢/kw-hr	0.0015	0.0075	0.015	0.022	0.030
Total ¢/kw-hr	0.209	0.211	0.222	0.232	0.247
Avg water consumption gal/kw-hr	0	0.014	0.101	0.374	0.707

Casper, Wyoming

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.148	0.117	0.078	0.039	0
Wet condenser cost ¢/kw-hr	0.0031	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.040	0.056	0.084	0.108	0.092
Fuel penalty ¢/kw-hr	0	0	0	0.013	0.070
Cooling tower ¢/kw-hr	0.0015	0.0075	0.015	0.027	0.030
Total ¢/kw-hr	0.193	0.197	0.208	0.229	0.255
Avg water consumption gal/kw-hr	0	0.008	0.088	0.362	0.701

Beulah, North Dakota

Fraction designed dry	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.139	0.092	0.046	0
Wet condenser cost ¢/kw-hr	0.016	0.031	0.047	0.063
Electric energy ¢/kw-hr	0.048	0.072	0.112	0.088
Fuel penalty ¢/kw-hr	0	0	0.004	0.050
Cooling tower ¢/kw-hr	0.007	0.015	0.022	0.030
Total ¢/kw-hr	0.21	0.215	0.231	0.231
Avg water consumption gal/kw-hr	0	0.058	0.265	0.671

TABLE 2-3. (concluded)

UNIT COSTS - SET NO. 3

Farmington, New Mexico

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.119	0.094	0.063	0.029	0
Wet condenser cost ¢/kw-hr	0.0023	0.012	0.023	0.035	0.047
Electric energy ¢/kw-hr	0.024	0.032	0.046	0.057	0.046
Fuel penalty ¢/kw-hr	0	0	0.0008	0.0075	0.0285
Cooling tower ¢/kw-hr	0.0011	0.0055	0.011	0.016	0.022
Total ¢/kw-hr	0.146	0.144	0.144	0.144	0.144
Avg water consumption gal/kw-hr	0	0.014	0.101	0.374	0.707

Casper, Wyoming

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.113	0.089	0.060	0.030	0
Wet condenser cost ¢/kw-hr	0.0023	0.012	0.023	0.035	0.047
Electric energy ¢/kw-hr	0.020	0.028	0.042	0.054	0.046
Fuel penalty ¢/kw-hr	0	0	0	0.0064	0.035
Cooling tower ¢/kw-hr	0.0011	0.0055	0.011	0.016	0.022
Total ¢/kw-hr	0.136	0.135	0.136	0.141	0.150
Avg water consumption gal/kw-hr	0	0.008	0.088	0.362	0.701

Beulah, North Dakota

Fraction designed dry	0.75	0.50	0.25	0
Dry condenser cost ¢/kw-hr	0.100	0.070	0.035	0
Wet condenser cost ¢/kw-hr	0.012	0.023	0.035	0.047
Electric energy ¢/kw-hr	0.024	0.036	0.056	0.044
Fuel penalty ¢/kw-hr	0	0	0.002	0.025
Cooling tower ¢/kw-hr	0.0055	0.011	0.016	0.022
Total ¢/kw-hr	0.142	0.140	0.144	0.138
Avg water consumption gal/kw-hr	0	0.058	0.265	0.671

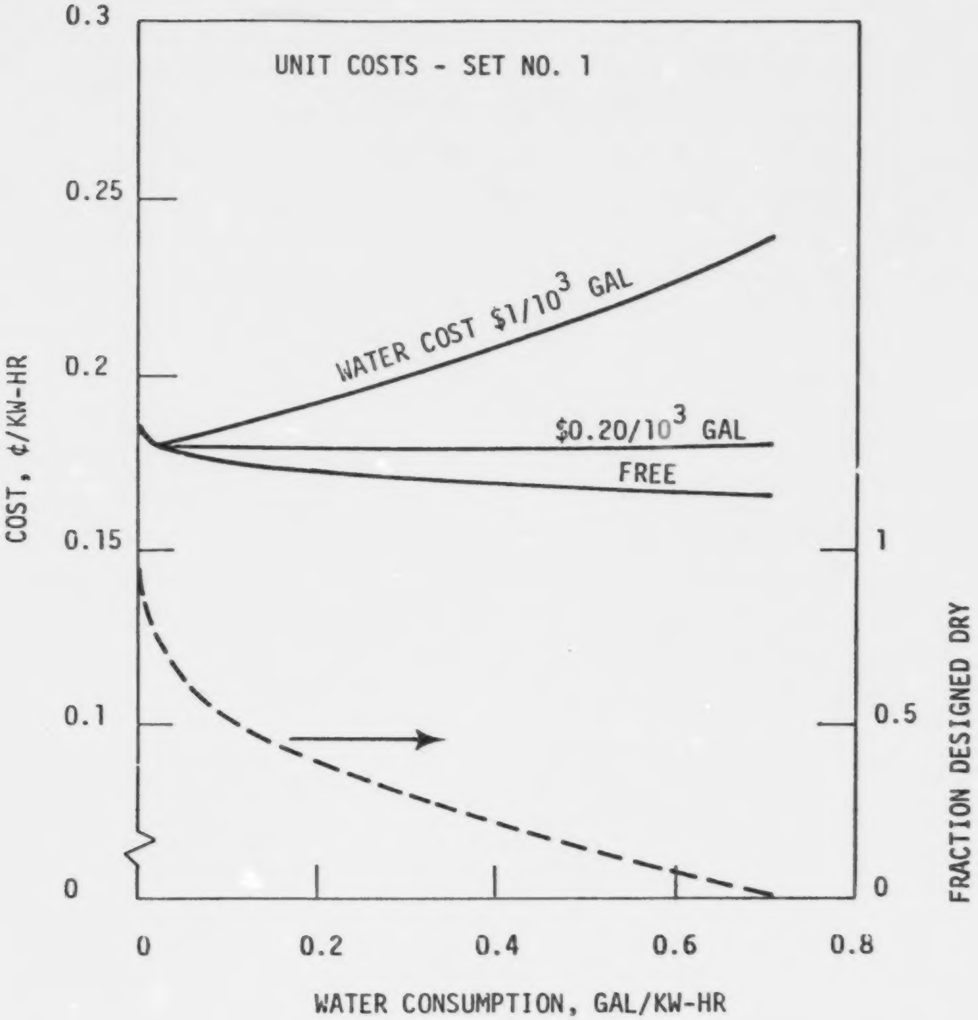

Figure 2-1. Cost of steam turbine condenser cooling in Farmington, New Mexico.

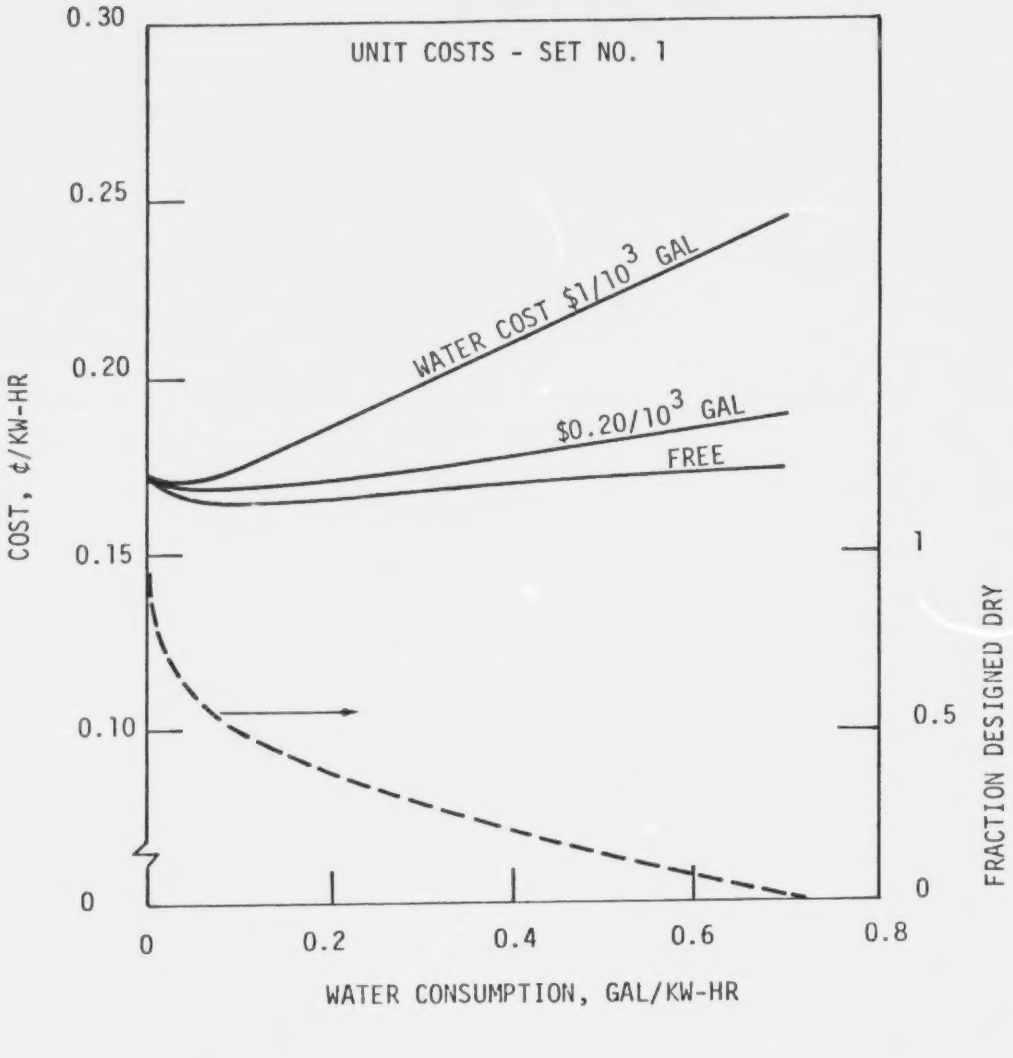

Figure 2-2. Cost of steam turbine condenser cooling in Casper, Wyoming.

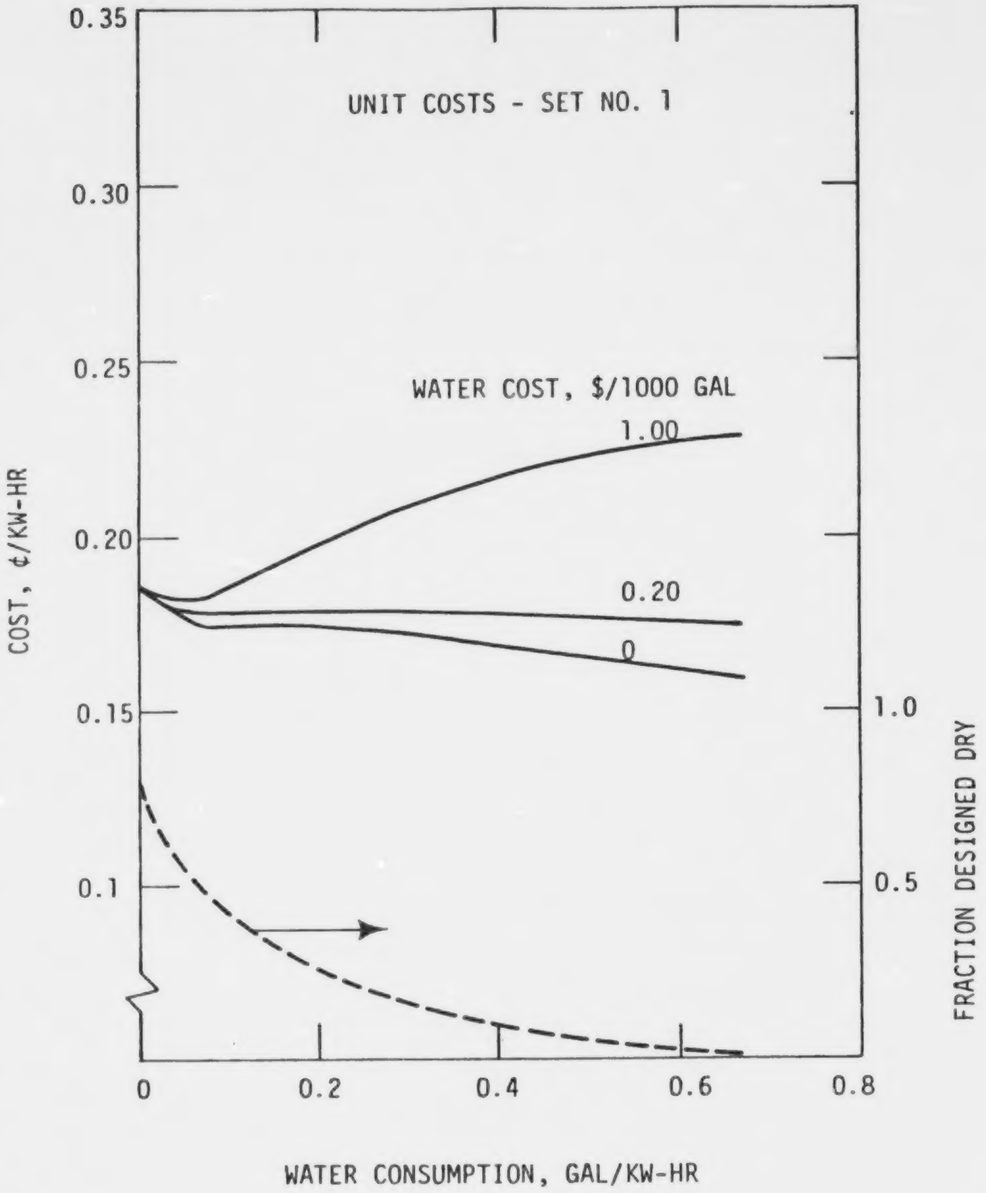

Figure 2-3. Cost of steam turbine condenser cooling in Beulah, North Dakota.

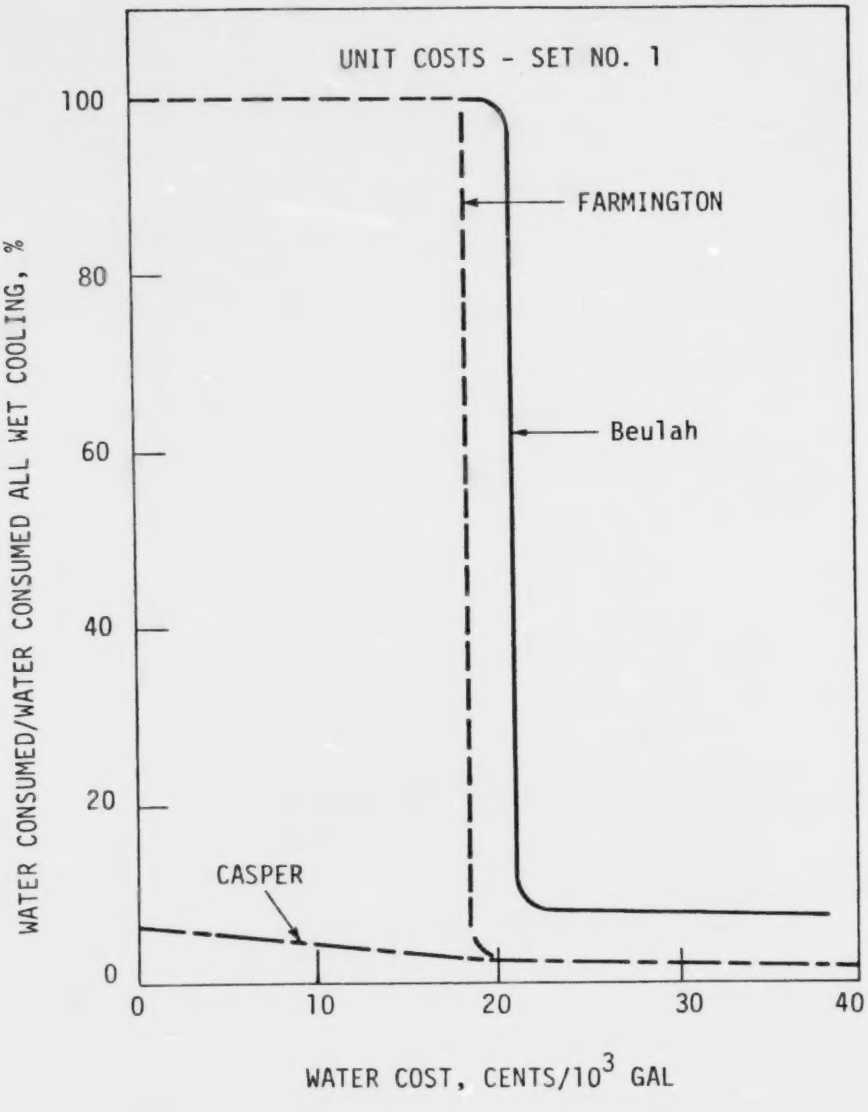

Figure 2-4. The effect of water cost on water consumed for cooling turbine condensers.

shows that when water costs more than about 20¢/10^3 gal, combined wet/dry cooling should be used and the water consumption will be less than 10 percent of the consumption with all wet cooling.

For sets numbers 2 and 3, graphs are not necessary. At most sites the total cost increases as the fraction of wet cooling increases, even when water is free. In no case will wet cooling be used if water costs more than 10¢/10^3 gal--and water always costs more than 10¢/10^3 gal. Of course, small wet coolers must be provided for use during the daylight hours of the hottest summer days, but the annual water consumption for cooling will be close to zero.

The following conclusions apply for the cooling of condensers for steam turbines in coal conversion plants:

1) There is an excellent chance of saving money and water by using combined wet/dry condensers on condensing steam turbine drives; calculations should be made for all designs.

2) For most western sites, when water is not very abundant and not very cheap the water consumption estimates should be made on the assumption that parallel wet/dry condensers will be used on turbine drives and that the average water consumption will be less than 10 percent of the consumption for all-wet cooled condensers.

2.1.3 Economics of Cooling Air Compressors in Coal Conversion Plants

The three sets of unit costs on Table 2-2 were used with the summary of calculated results on wet/dry interstage cooling of an air compressor (from Section 2.3) to calculate the annual average costs tabulated on Table 2-4. The cost of compression energy in ¢/kw-hr is found by multiplying the steam cost in ¢/Btu by 11,700 Btu/kw-hr. As with turbine condensers, note that the "total costs" (¢/1000 lb) refer only to those costs dependent on the choice of the cooling system. Other cost components such as the purchase of the compressors are omitted.

The results are presented graphically on Figures 2-5 to 2-8 for unit cost set number 1, on Figures 2-9 to 2-12 for unit cost set number 2, and on Figures 2-13 to 2-16 for unit cost set number 3. Figures 2-8, 2-12 and 2-16 summarize the results for each of the three unit cost sets. From these figures

TABLE 2-4. ANNUAL AVERAGE COST FOR WET/DRY COMPRESSOR INTERSTAGE COOLING FOR AIR COMPRESSORS

UNIT COSTS - SET NO. 1

Farmington, New Mexico

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	3.123	2.139	1.432	0
Wet cooler cost, ¢/1000 lb	2.367	2.633	2.861	3.346
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.319
Fan and pump energy, ¢/1000 lb	1.408	1.102	0.88	0.498
Compression energy cost, ¢/1000 lb	58.164	58.538	58.734	59.246
Total, ¢/1000 lb compressed	65.142	64.543	64.088	63.409
Water consumed, gal/1000 lb	0.851	1.929	3.097	7.215

Casper, Wyoming

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	2.886	2.100	1.259	0
Wet cooler cost, ¢/1000 lb	2.367	2.633	2.861	3.332
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.314
Fan and pump energy, ¢/1000 lb	1.316	1.084	0.808	0.490
Compression energy cost, ¢/1000 lb	57.921	58.210	58.629	58.949
Total, ¢/1000 lb compressed	64.571	64.157	63.738	63.085
Water consumed, gal/1000 lb	0.868	1.779	3.275	6.965

Beulah, North Dakota

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	3.484	2.354	1.561	0
Wet cooler cost, ¢/1000 lb	2.365	2.645	2.886	3.454
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.347
Fan and pump energy, ¢/1000 lb	1.528	1.152	0.910	0.590
Compression energy cost, ¢/1000 lb	57.035	57.643	57.755	58.235
Total, ¢/1000 lb compressed	64.493	63.926	63.292	62.626
Water consumed, gal/1000 lb	0.584	1.447	2.221	6.686

TABLE 2-4. (continued)

UNIT COSTS - SET NO. 2

Farmington, New Mexico

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	3.122	2.138	1.432	0
Wet cooler cost, ¢/1000 lb	2.367	2.633	2.861	3.346
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.319
Fan and pump energy, ¢/1000 lb	2.816	2.204	1.760	0.996
Compression energy cost, ¢/1000 lb	116.327	117.077	117.468	118.492
Total, ¢/1000 lb compressed	124.721	124.183	123.701	123.153
Water consumed, gal/1000 lb	0.851	1.929	3.097	7.215

Casper, Wyoming

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	2.885	2.100	1.259	0
Wet cooler cost, ¢/1000 lb	2.367	2.633	2.861	3.332
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.314
Fan and pump energy, ¢/1000 lb	2.632	2.168	1.616	0.980
Compression energy cost, ¢/1000 lb	115.843	116.420	117.278	117.898
Total, ¢/1000 lb compressed	123.808	123.452	123.194	122.524
Water consumed, gal/1000 lb	0.868	1.779	3.275	6.965

Beulah, North Dakota

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	3.484	2.354	1.561	0
Wet cooler cost, ¢/1000 lb	2.365	2.645	2.886	3.454
Tower cost, ¢/1000 lb	0.081	0.131	0.180	0.347
Fan and pump energy, ¢/1000 lb	3.056	2.304	1.820	1.180
Compression energy cost, ¢/1000 lb	114.069	115.287	115.510	116.470
Total, ¢/1000 lb compressed	123.056	122.721	121.957	121.451
Water consumed, gal/1000 lb	0.584	1.447	2.221	6.686

TABLE 2-4. (concluded)

UNIT COSTS - SET NO. 3

Farmington, New Mexico

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	2.387	1.635	1.095	0
Wet cooler cost, ¢/1000 lb	1.893	2.106	2.289	2.677
Tower cost, ¢/1000 lb	0.059	0.096	0.132	0.234
Fan and pump energy, ¢/1000 lb	1.408	1.102	0.880	0.498
Compression energy cost, ¢/1000 lb	58.164	58.538	58.734	59.249
Total, ¢/1000 lb compressed	63.911	63.478	63.130	62.655
Water consumed, gal/1000 lb	0.851	1.929	3.097	7.215

Casper, Wyoming

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	2.206	1.605	0.962	0
Wet cooler cost, ¢/1000 lb	1.893	2.106	2.289	2.665
Tower cost, ¢/1000 lb	0.059	0.096	0.132	0.230
Fan and pump energy, ¢/1000 lb	1.316	1.084	0.808	0.490
Compression energy cost, ¢/1000 lb	57.921	58.210	58.629	58.949
Total, ¢/1000 lb compressed	63.396	63.101	62.821	62.334
Water consumed, gal/1000 lb	0.868	1.779	3.275	6.965

Beulah, North Dakota

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	2.664	1.800	1.194	0
Wet cooler cost, ¢/1000 lb	1.892	2.116	2.309	2.763
Tower cost, ¢/1000 lb	0.59	0.096	0.132	0.254
Fan and pump energy, ¢/1000 lb	1.528	1.152	0.910	0.590
Compression energy cost, ¢/1000 lb	57.035	57.643	57.755	58.235
Total, ¢/1000 lb compressed	63.179	62.808	62.300	61.843
Water consumed, gal/1000 lb	0.584	1.447	2.221	6.686

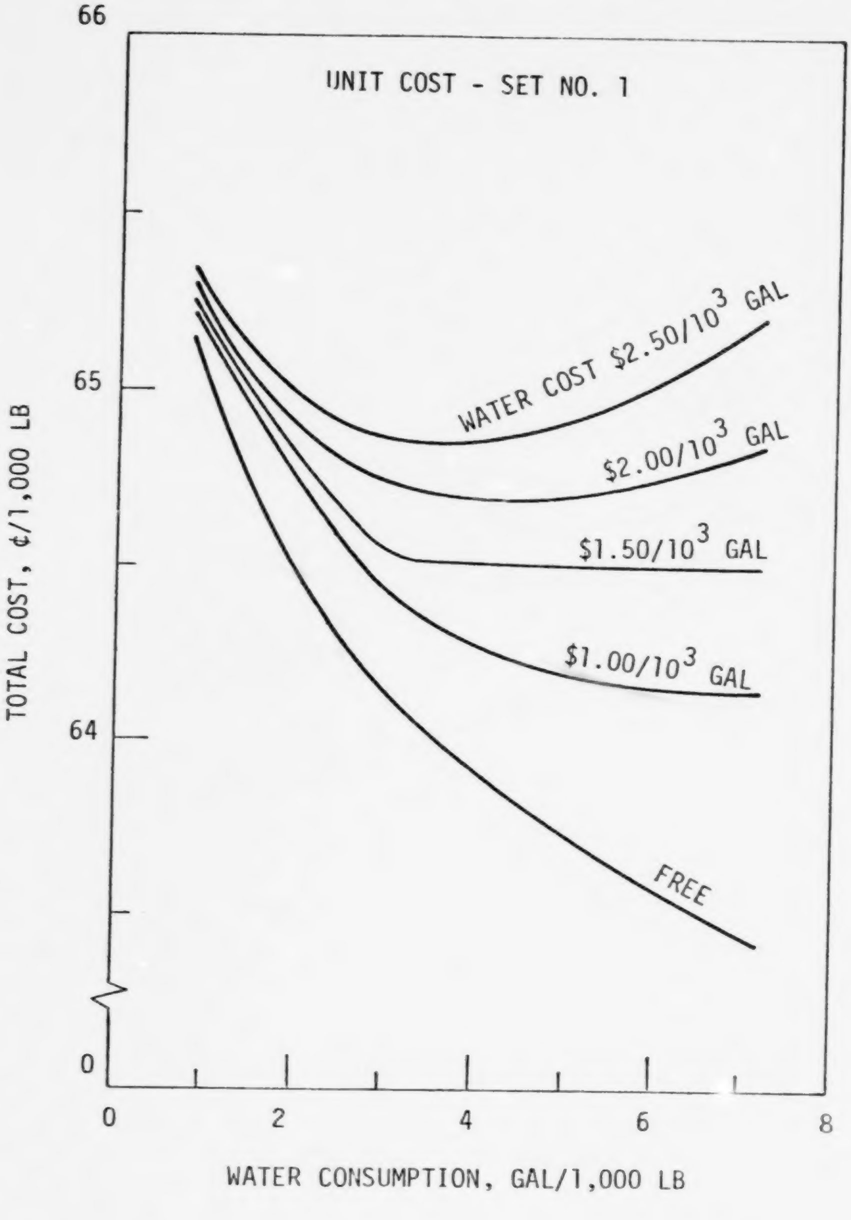

Figure 2-5. Cost of interstage cooling for compressing 1,000 lb air at Farmington, New Mexico. (Unit cost - Set No. 1)

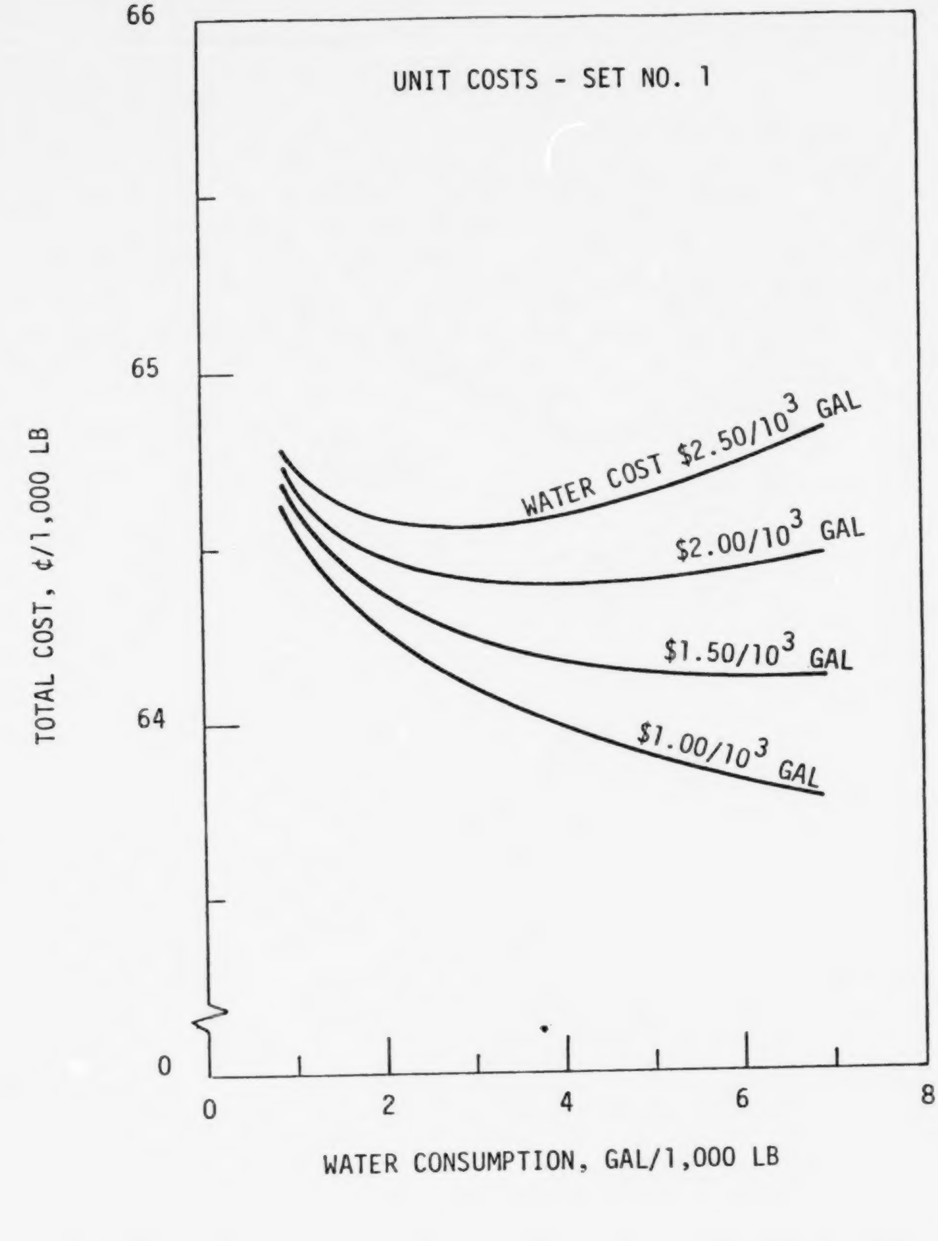

Figure 2-6. Cost of interstage cooling for compressing 1,000 lb air at Casper, Wyoming. (Unit cost - set No. 1)

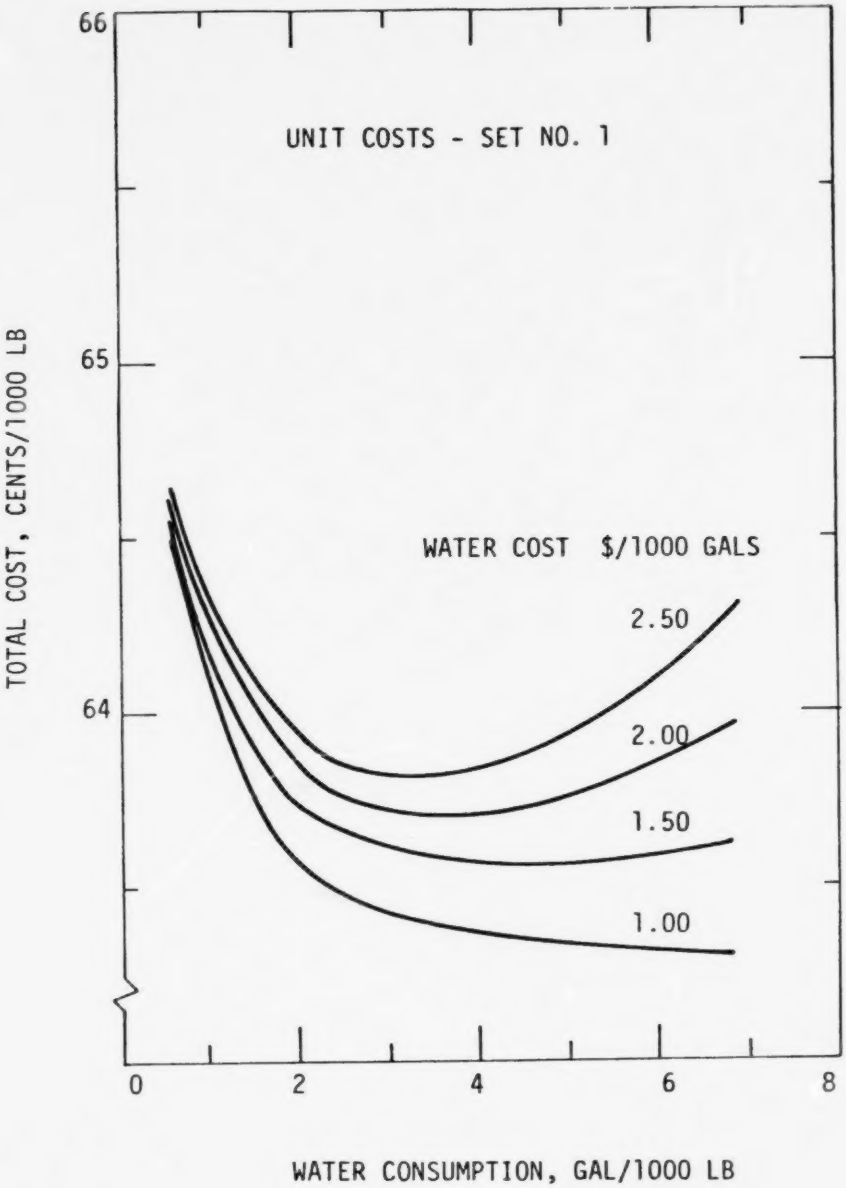

Figure 2-7. Cost of interstage cooling for compressing 1,000 lb air at Beulah, North Dakota. (Unit cost - Set No. 1)

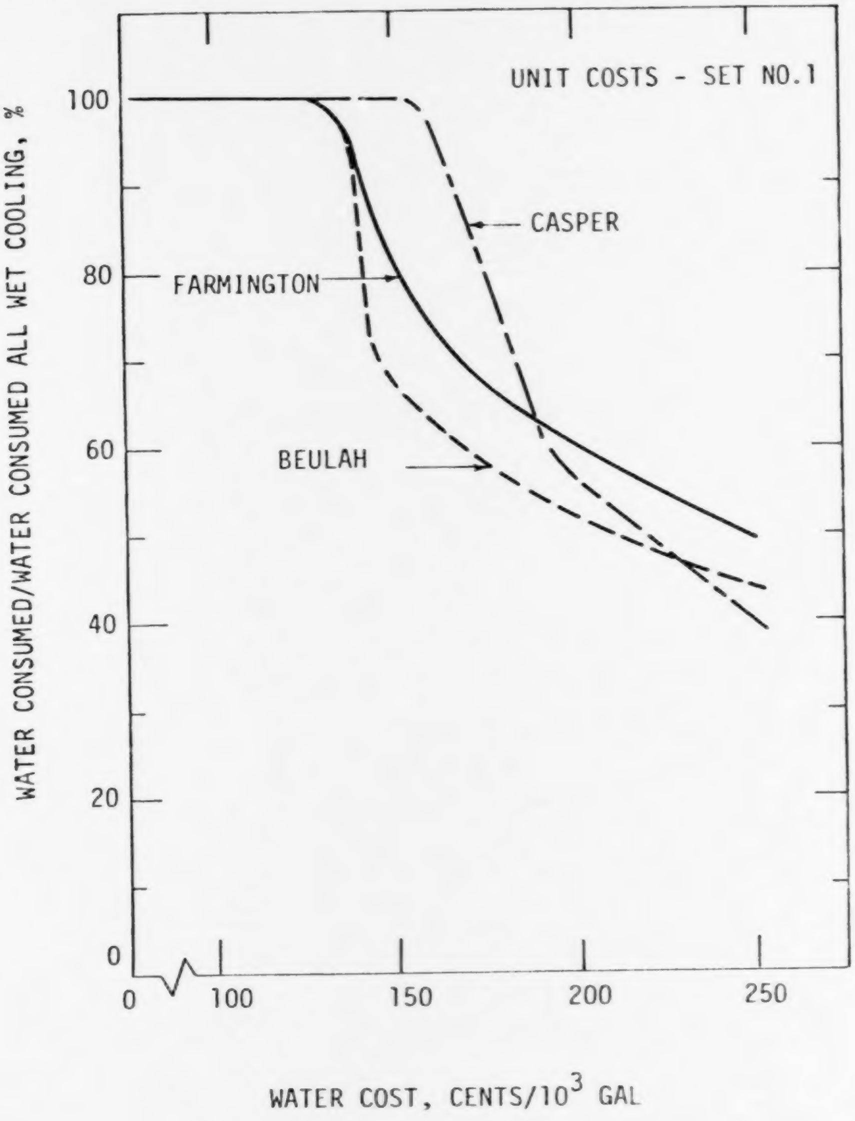

Figure 2-8. The effect of water cost on water consumed for interstage cooling when compressing 1,000 lb air. (Unit cost - Set No.1)

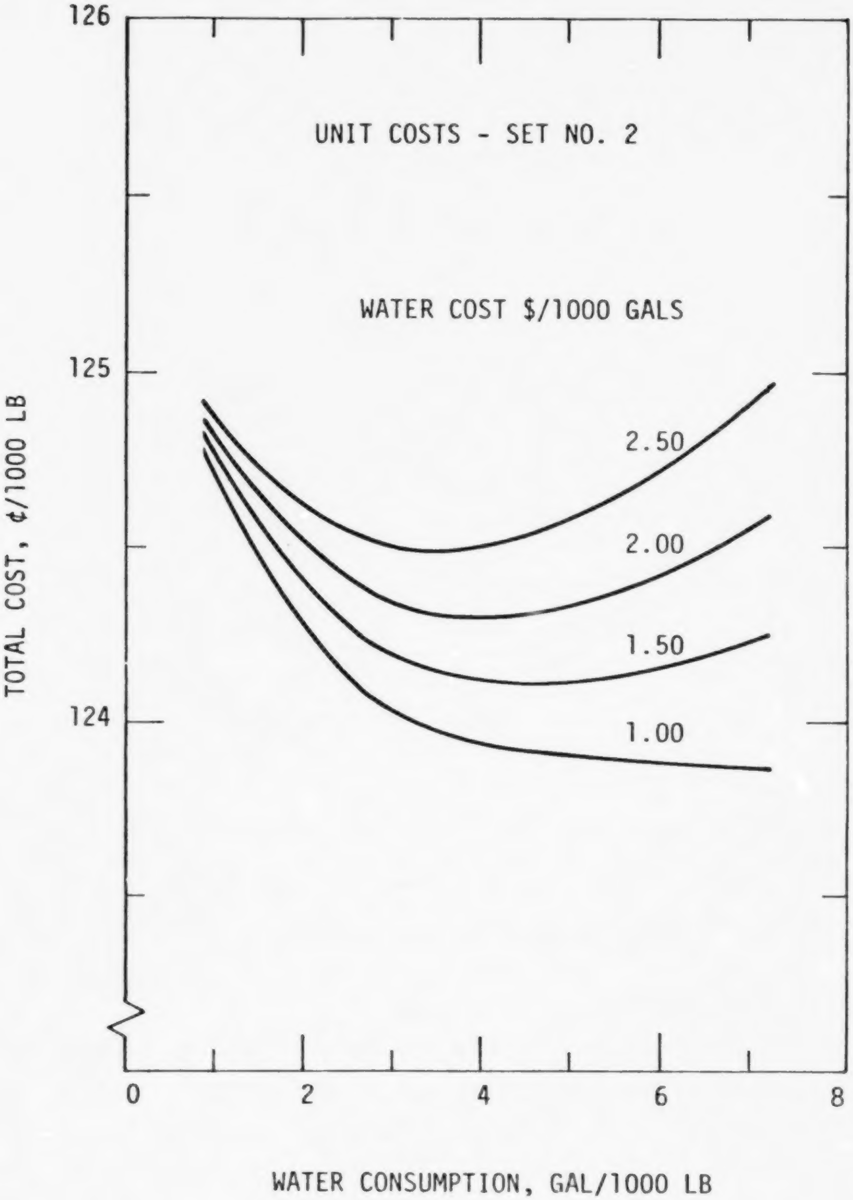

Figure 2-9. Cost of interstage cooling for compressing 1000 lb air at Farmington, New Mexico. (Unit cost - Set No. 2)

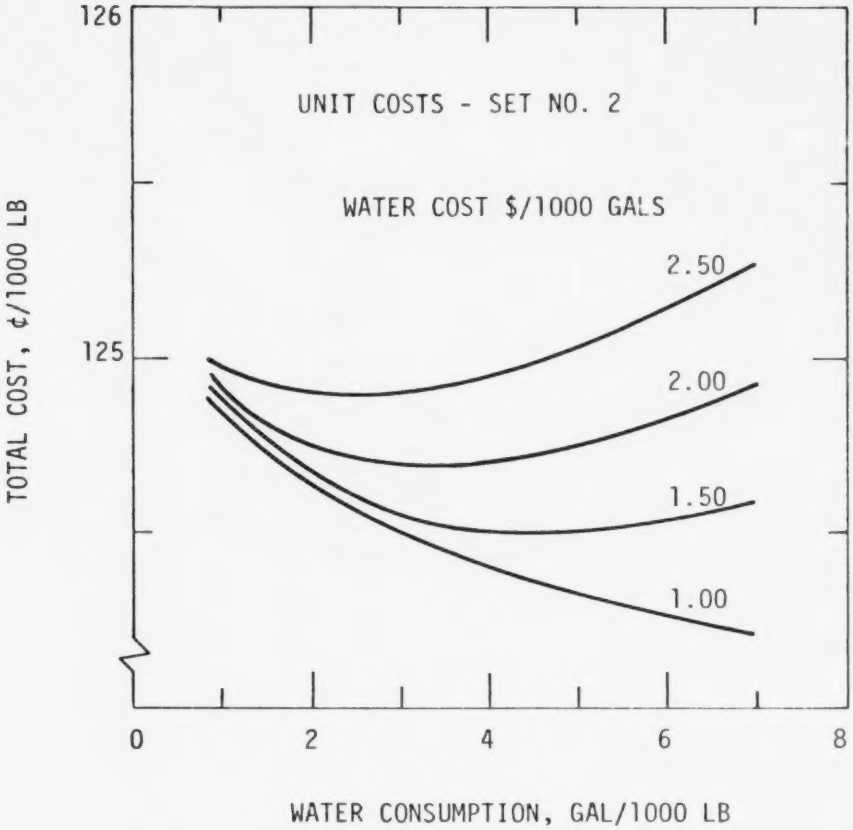

Figure 2-10. Cost of interstage cooling for compressing 1000 lb air at Casper, Wyoming. (Unit cost - Set No. 2)

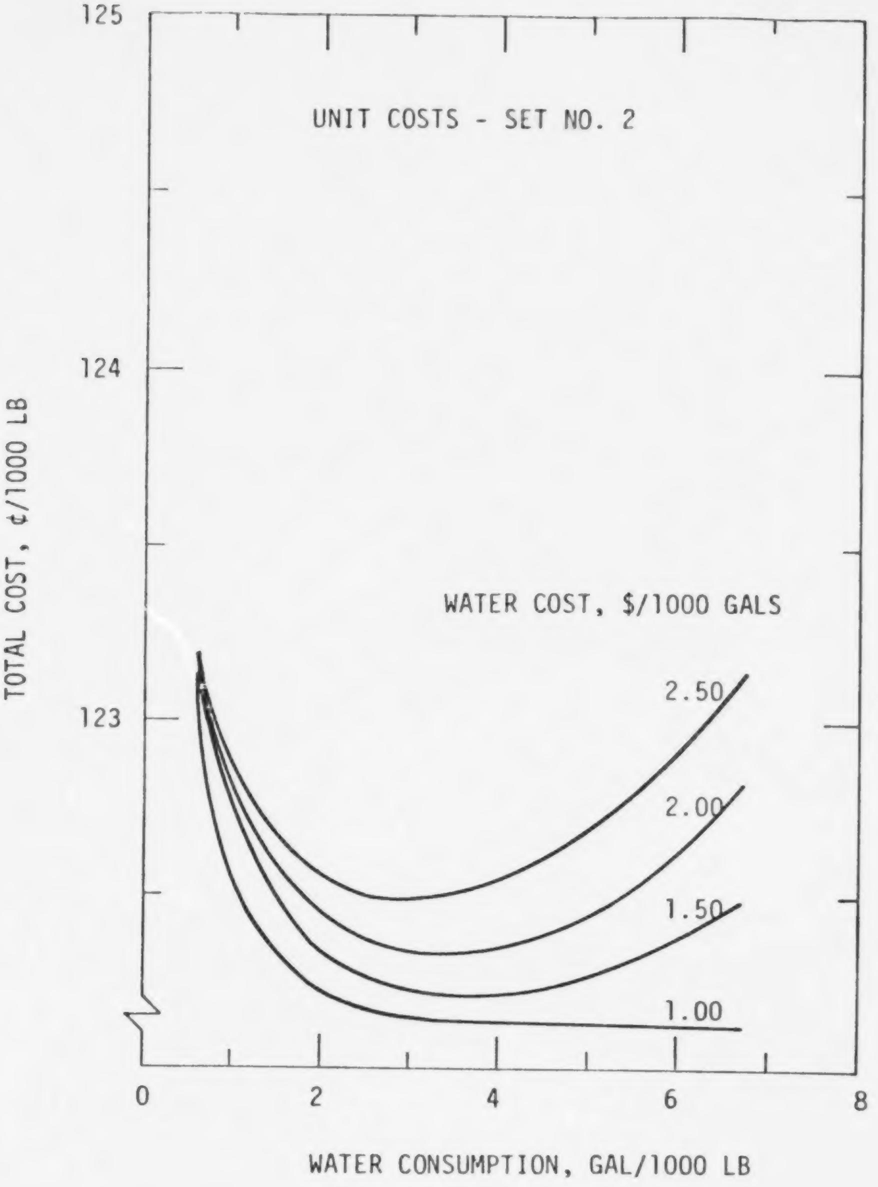

Figure 2-11. Cost of interstage cooling for compressing 1000 lb air at Beulah, North Dakota. (Unit cost - Set No. 2)

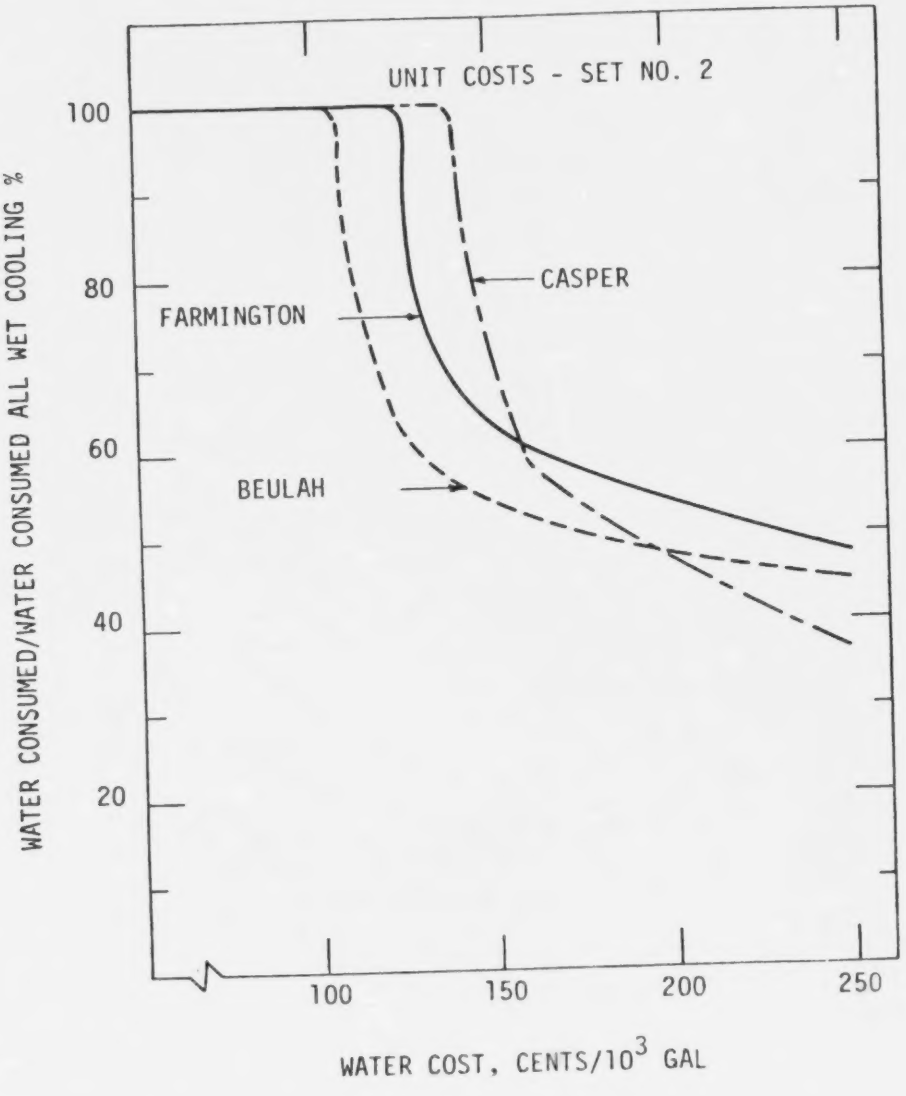

Figure 2-12. The effect of water cost on water consumed for interstage cooling when compressing 1000 lb air. (Unit cost - Set No. 2)

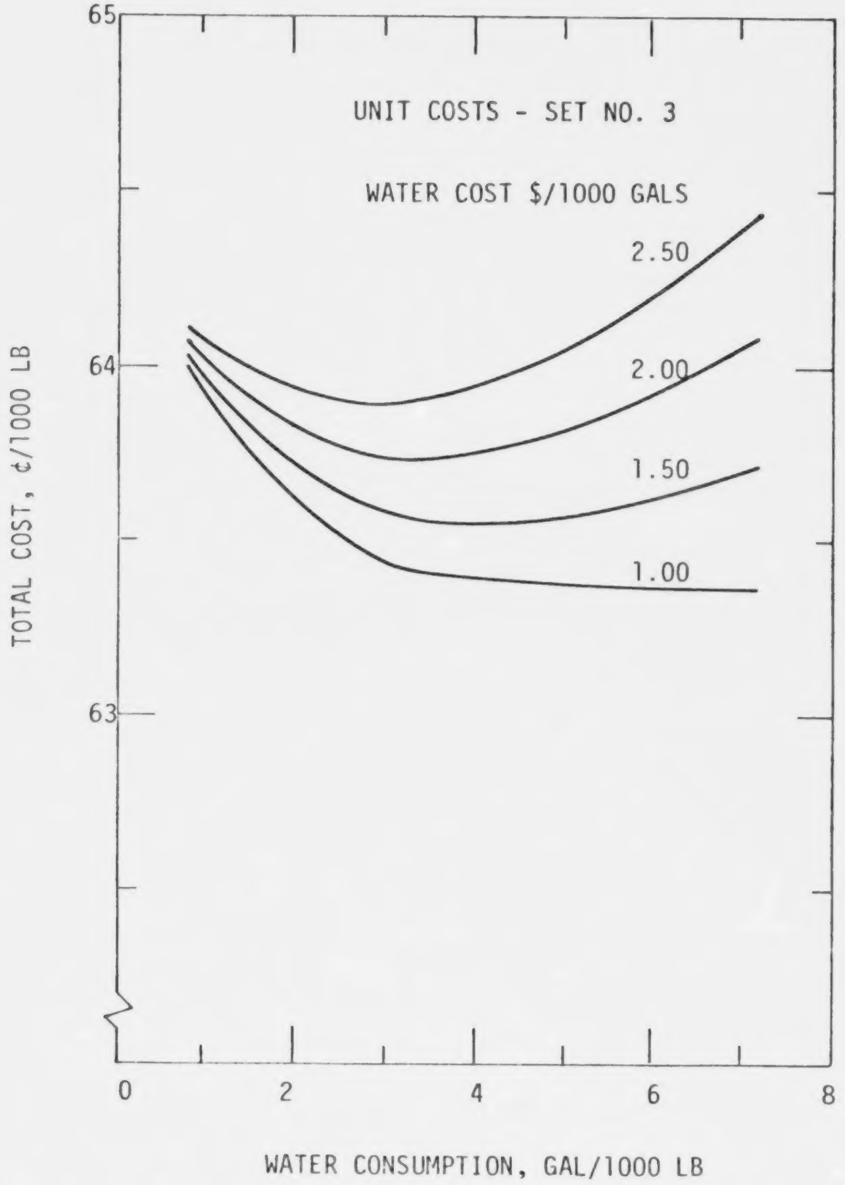

Figure 2-13. Cost of interstage cooling for compressing 1000 lb air at Farmington, New Mexico. (Unit cost - Set No. 3)

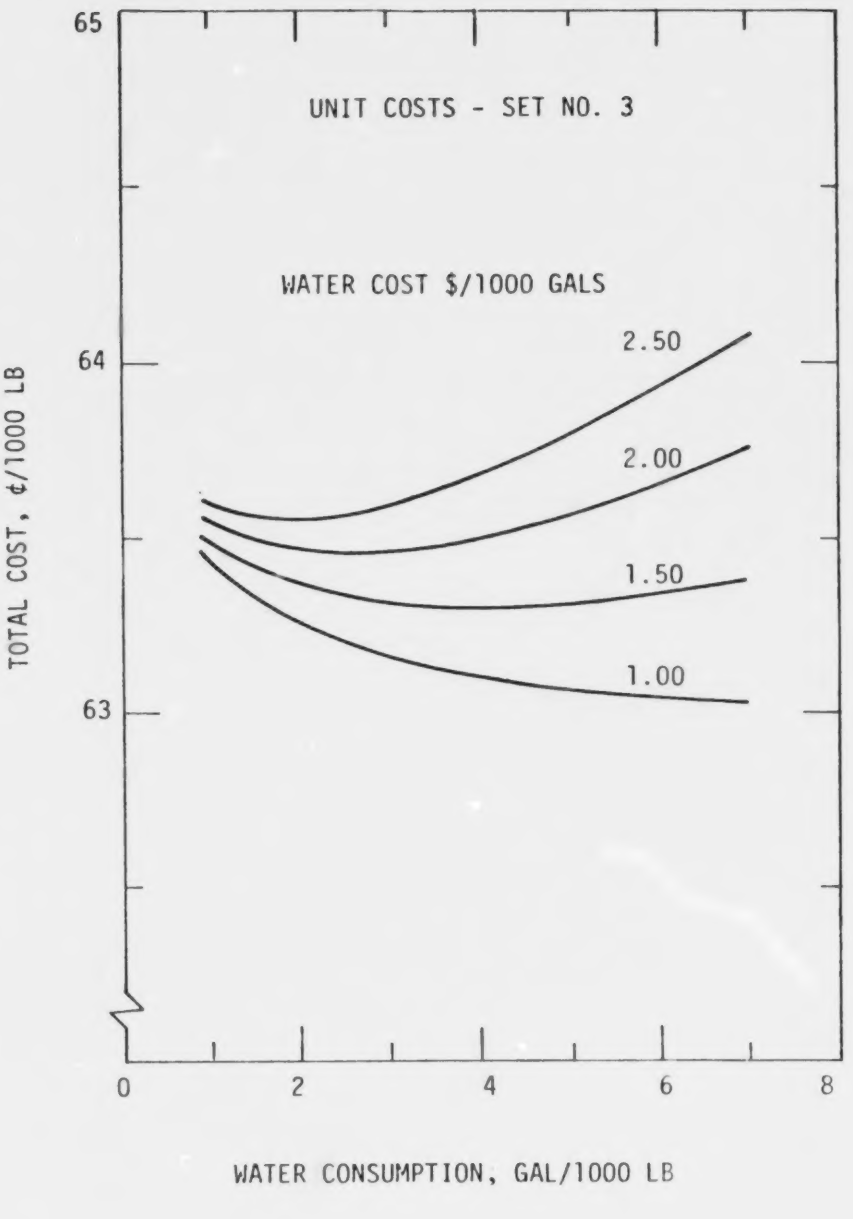

Figure 2-14. Cost of interstage cooling for compressing 1000 lb air at Casper, Wyoming. (Unit cost - Set No. 3)

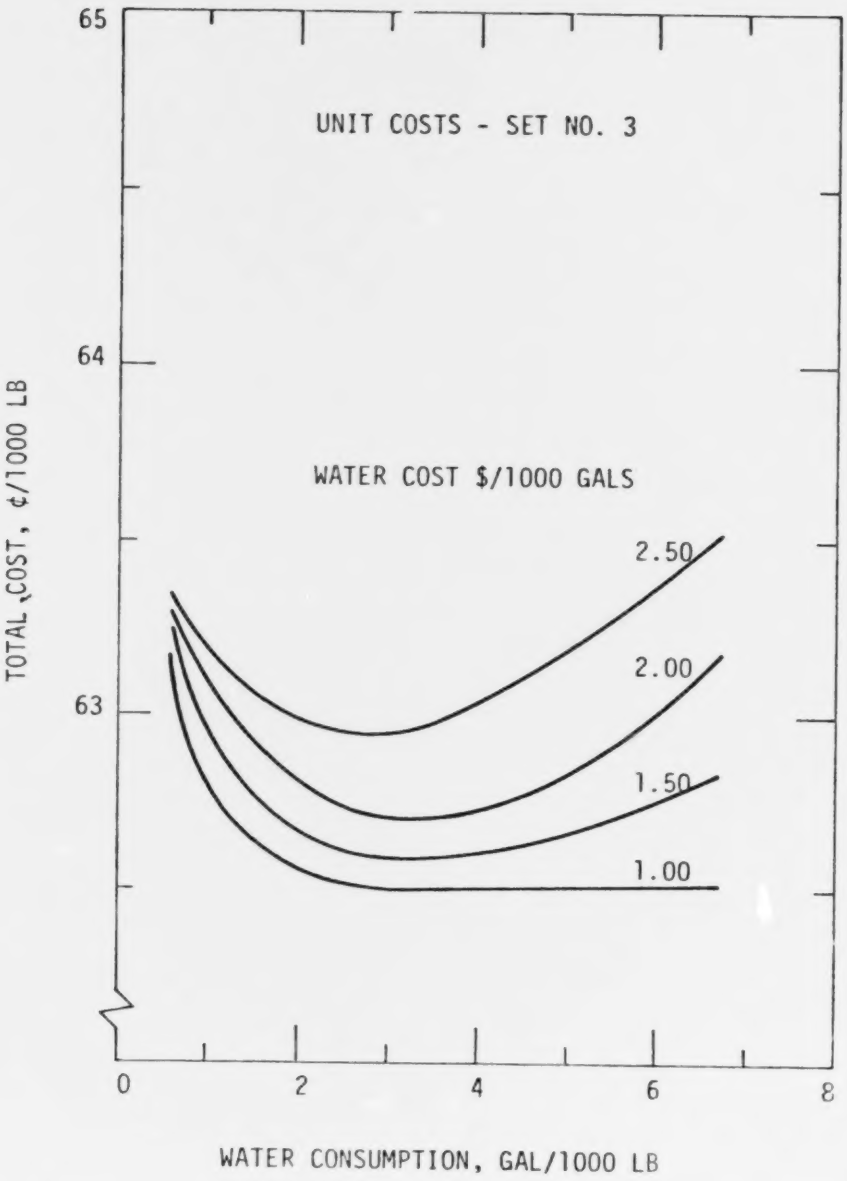

Figure 2-15. Cost of interstage cooling for compressing 1000 lb air at Beulah, North Dakota (Unit cost - Set No. 3)

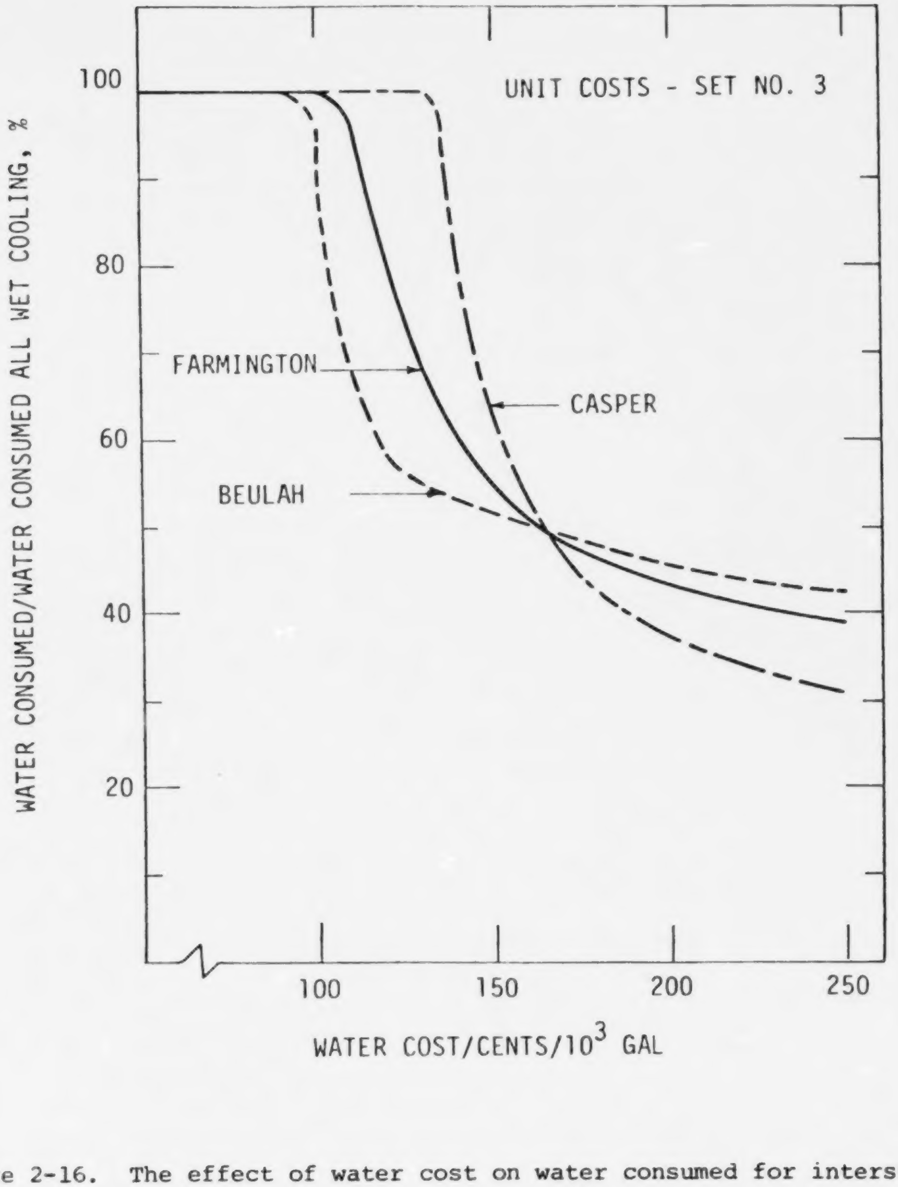

Figure 2-16. The effect of water cost on water consumed for interstage cooling when compressing 1000 lb air. (Unit cost - Set No. 3)

we can draw the following conclusions which, it must be remembered, apply to a compressor compressing air from atmospheric pressure to 90 psia:

1) There is cost of water above which it pays to use dry followed by wet interstage cooler. This cost of water is high, but not ridicuously high; for our unit costs the change occurs when water costs between $1.00 and $1.50 per 10^3 gallons.

2) Should energy costs increase more than the capital costs, partial dry cooling will be introduced at lower costs of water.

3) For some western sites, where water is moderately expensive and moderately scarce, water consumption estimates should be made on the assumption that series dry/wet interstage coolers are used. The water consumption will be 50 to 60 percent of the consumption for all wet coolers.

2.1.4 Economics of Cooling Hydrogen Compressors in Coal Conversion Plants

The three sets of unit costs on Table 2-2 were used with the summary of calculated results on wet/dry interstage cooling of a hydrogen compressor, from Section 2.4, to calculate the annual average costs tabulated on Table 2-5.

A single cost graph has been prepared for Farmington, New Mexico using unit costs set number 1. Figure 2-17 shows not only the total cost but also the capital cost (dry area plus wet area plus cooling tower), the auxiliary fan and pump energy cost, and the compression energy cost. Although the cost scales are different for different curves, the difference is only in a displacement of zero; the scale intervals are the same for all the curves. This makes it simple to see that changes in the cost of compression energy dominate the other changes in cost. The molecular weight of hydrogen is very low and compression energy is very high. When dry interstage coolers are compared to wet coolers, it is found that dry cooling gives a lot lower temperature in winter than does wet cooling, but that wet cooling is not so much more effective than dry cooling in the summer.

For all unit cost sets studied, at all sites, dry cooling is preferred. Small wet coolers will be installed for use on the hottest days of the year, but for estimating purposes, interstage coolers on the hydrogen compressor studied can be assumed to consume no water.

TABLE 2-5. ANNUAL AVERAGE COST FOR WET/DRY COMPRESSOR INTERSTAGE COOLING FOR HYDROGEN COMPRESSORS

UNIT COSTS - SET NO. 1

Farmington, New Mexico

Basis: 1000 lb hydrogen compressed/hr

Design intermediate temperature, °F	all dry	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	11.623	7.261	5.472	4.162	0
Wet cooler cost, ¢/1000 lb	0	4.395	4.986	5.474	7.142
Tower cost, ¢/1000 lb	0	0.736	1.211	1.472	4.311
Fan and pump energy, ¢/1000 lb	5.662	4.686	4.558	4.830	6.732
Compression energy cost, ¢/1000 lb	1119.840	1133.500	1166.141	1167.267	1177.510
Total, ¢/1000 lb compressed	1137.125	1150.578	1182.368	1183.206	1195.796
Water consumed, gal/1000 lb	0	10.253	20.937	27.684	107.939

Casper, Wyoming

Basis: 1000 lb hydrogen compressed/hr

Design intermediate temperature, °F	all dry	160	all wet
Dry cooler cost, ¢/1000 lb	11.145	5.373	0
Wet cooler cost, ¢/1000 lb	0	4.986	7.142
Tower cost, ¢/1000 lb	0	1.211	4.311
Fan and pump energy, ¢/1000 lb	5.428	4.510	6.732
Compression energy cost, ¢/1000 lb	1136.115	1139.666	1181.154
Total, ¢/1000 lb compressed	1152.688	1155.747	1199.338
Water consumed, gal/1000 lb	0	19.816	106.801

Beulah, North Dakota

Basis: 1000 lb. hydrogen compressed/hr

Design intermediate temperature, °F	all dry	160	all wet
Dry cooler cost, ¢/1000 lb	12.785	5.669	0
Wet cooler cost, ¢/1000 lb	0	4.986	7.142
Tower cost, ¢/1000 lb	0	1.211	4.311
Fan and pump energy, ¢/1000 lb	6.226	4.654	6.732
Compression energy cost, ¢/1000 lb	1175.522	1159.547	1175.704
Total, ¢/1000 lb compressed	1144.533	1176.067	1193.888
Water consumed, gal/1000 lb	0	16.6	107

TABLE 2-5. (continued)

UNIT COSTS - SET NO. 2

Farmington, New Mexico

Basis: 1000 lb hydrogen compressed/hr

Design intermediate temperature, °F	all dry	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	11.623	7.261	5.472	4.162	0
Wet cooler cost, ¢/1000 lb	0	4.395	4.986	5.474	7.142
Tower cost, ¢/1000 lb	0	0.736	1.211	1.471	4.311
Fan and pump energy, ¢/1000 lb	11.324	9.372	9.116	9.660	13.404
Compression energy cost, ¢/1000 lb	2239.68	2267.0	2332.4	2334.5	2355.2
Total, ¢/1000 lb compressed	2262.6	2288.8	2353.1	2355.3	2380.1
Water consumed, gal/1000 lb	0	10.253	20.937	27.684	107.939

Casper, Wyoming

Basis: 1000 lb hydrogen compressed/hr

Design intermediate temperature, °F	all dry	160	all wet
Dry cooler cost, ¢/1000 lb	11.145	5.373	0
Wet cooler cost, ¢/1000 lb	0	4.986	7.142
Tower cost, ¢/1000 lb	0	1.211	4.311
Fan and pump energy, ¢/1000 lb	10.850	9.020	13.464
Compression energy cost, ¢/1000 lb	2272.2	2279.3	2362.3
Total, ¢/1000 lb compressed	2294.2	2300.0	2387.2
Water consumed, gal/1000 lb	0	19.816	106.801

Beulah, North Dakota

Basis: 1000 lb. hydrogen compressed/hr

Design intermediate temperature, °F	all dry	160	all wet
Dry cooler cost, ¢/1000 lb	12.785	5.669	0
Wet cooler cost, ¢/1000 lb	0	4.986	7.142
Tower cost, ¢/1000 lb	0	1.211	4.311
Fan and pump energy, ¢/1000 lb	12.452	9.308	13.464
Compression energy cost, ¢/1000 lb	2251.0	2319.1	2351.4
Total, ¢/1000 lb compressed	2276.3	2340.3	2376.3
Water consumed, gal/1000 lb	0	16.6	107

TABLE 2-5. (concluded)

UNIT COSTS - SET NO. 3

Farmington, New Mexico

Basis: 1000 lb hydrogen compressed/hr

Design intermediate temperature, °F	all dry	140	160	180	all wet
Dry cooler cost, ¢/1000 lb	8.888	5.553	4.184	3.183	0
Wet cooler cost, ¢/1000 lb	0	3.516	3.989	4.379	5.714
Tower cost, ¢/1000 lb	0	0.540	0.888	1.079	3.161
Fan and pump energy, ¢/1000 lb	5.662	4.686	4.558	4.830	6.732
Compression energy cost, ¢/1000 lb	1119.8	1133.5	1166.1	1167.3	1177.6
Total, ¢/1000 lb compressed	1128.7	1147.8	1179.7	1180.8	1193.2
Water consumed, gal/1000 lb	0	10.3	20.9	27.7	107.9

Casper, Wyoming

Basis: 1000 lb hydrogen compressed/hr

Design intermediate temperature, °F	all dry	160	all wet
Dry cooler cost, ¢/1000 lb	8.523	4.109	0
Wet cooler cost, ¢/1000 lb	0	3.989	5.714
Tower cost, ¢/1000 lb	0	0.888	3.161
Fan and pump energy, ¢/1000 lb	5.428	4.510	6.732
Compression energy cost, ¢/1000 lb	1136.1	1139.7	1181.1
Total, ¢/1000 lb compressed	1150.1	1153.2	1196.7
Water consumed, gal/1000 lb	0	19.8	106.8

Beulah, North Dakota

Basis: 1000 lb. hydrogen compressed/hr

Design intermediate temperature, °F	all dry	160	all wet
Dry cooler cost, ¢/1000 lb	9.777	4.335	0
Wet cooler cost, ¢/1000 lb	0	3.989	5.714
Tower cost, ¢/1000 lb	0	0.888	3.161
Fan and pump energy, ¢/1000 lb	6.226	4.654	6.732
Compression energy cost, ¢/1000 lb	1125.5	1159.5	1175.7
Total, ¢/1000 lb compressed	1141.5	1173.4	1191.3
Water consumed, gal/1000 lb	0	16.6	107

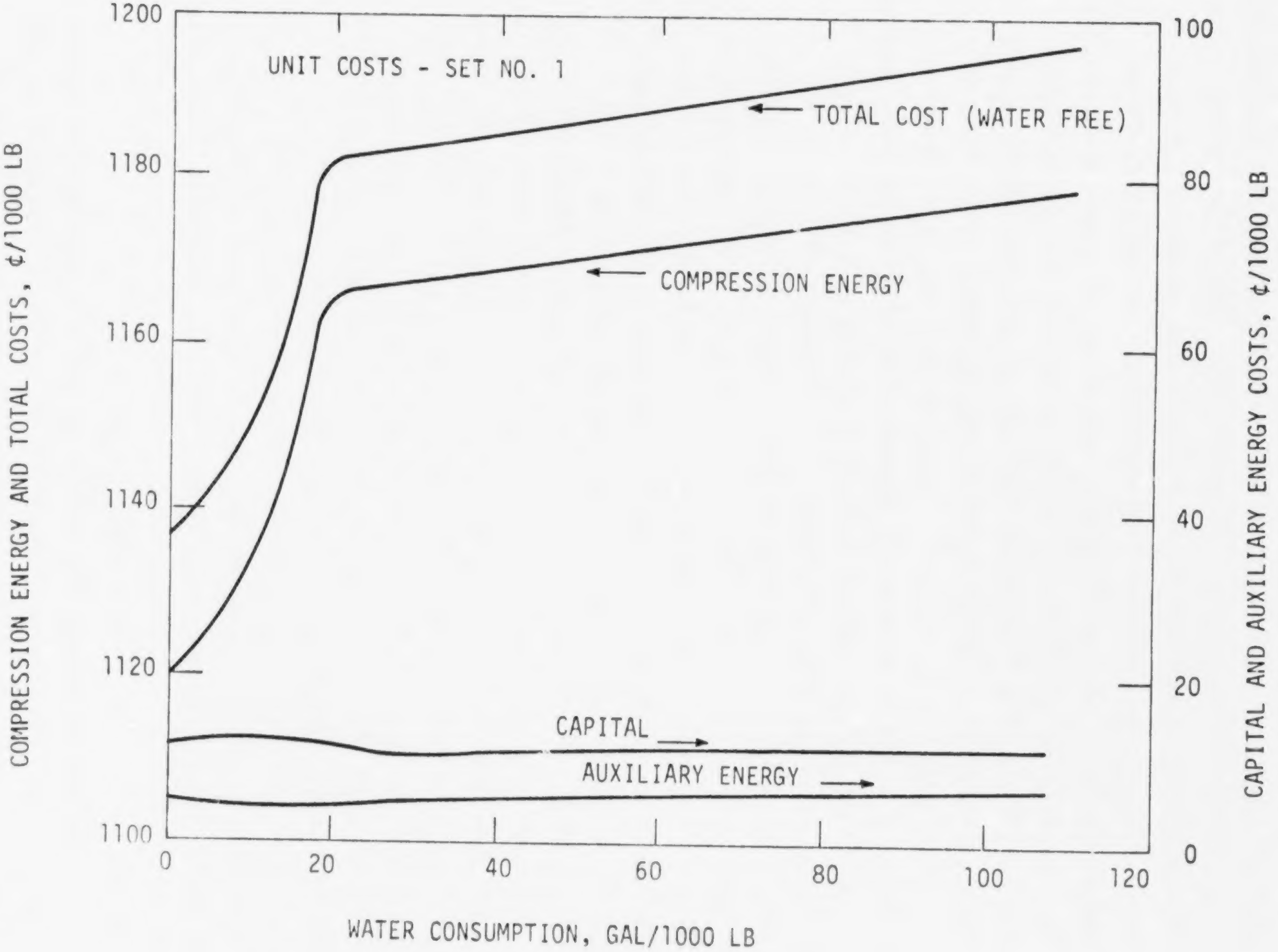

Figure 2-17. Cost of interstage cooling for compressing 1000 lb hydrogen at Farmington, New Mexico.

2.1.5 Economics of Cooling Turbine Condensers in Steam Generating Plant

Tables 2-6 and 2-7 summarize the costs and evaporation rates of economically optimum systems for the wet/dry cooling of turbine condensers in steam generating plants for a range of fixed charge rates and fuel costs. Figure 2-18 shows schematically the operating costs of cooling steam turbine condensers as a function of water consumed for different costs of water. If water is free or its cost is negligible, then an all wet cooling system is the lowest cost cooling system. As the cost of water increases, the cost of wet/dry cooling systems becomes comparable with the all wet system, but with a much lower water consumption. When the cost of water is equal to the changeover water cost, then the annual cost of operating a wet/dry system is equal to the cost of an all wet system. When the cost of water exceeds the changeover water cost, wet/dry cooling is more desirable, while all wet cooling is more desirable when the cost of water is lower than the changeover water cost. (See Figure 2-18).

The changeover water costs range from \$3.65 to \$5.47 per 1000 gals water evaporated in North Dakota and \$3.83 to \$5.87 per 1000 gals water evaporated in New Mexico for the fixed charge rates and fuel costs considered. These costs are much higher than the changeover water costs previously found for cooling turbine condensers and gas comparessors in plants producing synthetic fuel from coal. The variation in changeover water cost is primarily dependent on the variation in the fixed charge rate and is relatively independent of the fuel cost.

We have also shown the busbar energy cost penalty of using a wet/dry cooling tower in preference to an all wet cooling tower. The cost penalty is the difference in the optimum operating cost of a wet/dry tower at the changeover water cost to the optimum cost of an all wet tower when the water is free divided by the output of the power plant in kw-hrs. The penalty cost ranges from 1.2 to 2.0 mils/kw-hr (0.12 -0.2 ¢/kw-hr) as compared to a delivered cost of electricity of 2¢/kw-hr, commonly used today. This would represent the maximum penalty since water is not free and would rarely exceed the changeover water cost. The cost of wet/dry towers is relatively insensitive to the water costs near the design optimum.

The primary advantage of the wet/dry system is that the consumptive use of water can be drastically reduced from that of an all wet tower. Tables 2-6 and 2-7 show that at the design optimum the evaporative water consumption is reduced

TABLE 2-6. SUMMARY OF WET/DRY COOLING SYSTEM COSTS AND WATER REQUIREMENTS AT NAVAJO/FARMINGTON, NEW MEXICO

Fixed Charge Rate (Percent)	Fuel Cost ($\$/10^6$ Btu)	Changeover Water Cost ($/1000 gals Evaporated)	Busbar Energy Cost Penalty (Mils/kwhr)	Evaporation Rate* (gals/cal min)	Evaporation Rate as Percent of All Wet Cooling
15	0.50	3.83	1.40	693	14.6
	1.00	4.16	1.53	686	14.4
	1.50	4.34	1.65	534	11.2
18	0.50	4.43	1.56	847	17.8
	1.00	4.80	1.76	686	14.6
	1.50	5.18	1.82	856	18.0
21	0.50	5.03	1.77	847	17.8
	1.00	5.44	1.84	1012	21.3
	1.50	5.87	1.97	1028	21.6

---

*For 1000 MWe steam-electric power plant.

TABLE 2-7. SUMMARY OF WET/DRY COOLING SYSTEM COSTS AND WATER REQUIREMENTS AT BEULAH, NORTH DAKOTA

Fixed Charge Rate (Percent)	Fuel Cost ($/$10^6$ Btu)	Changeover Water Cost ($/1000 gals Evaporated)	Busbar Energy Cost Penalty (Mils/kwhr)	Evaporation Rate* (gals/cal min)	Evaporation Rate as Percent of All Wet Cooling
15	0.50	3.65	1.21	661	15.2
	1.00	4.16	1.31	650	15.0
	1.50	4.34	1.44	513	11.8
18	0.50	4.43	1.43	661	14.9
	1.00	4.80	1.52	650	15.0
	1.50	5.18	1.67	513	11.8
21	0.50	5.03	1.63	661	14.9
	1.00	5.44	1.75	651	15.0
	1.50	5.87	1.89	513	11.8

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*For 1000 MWe steam-electric power plant.

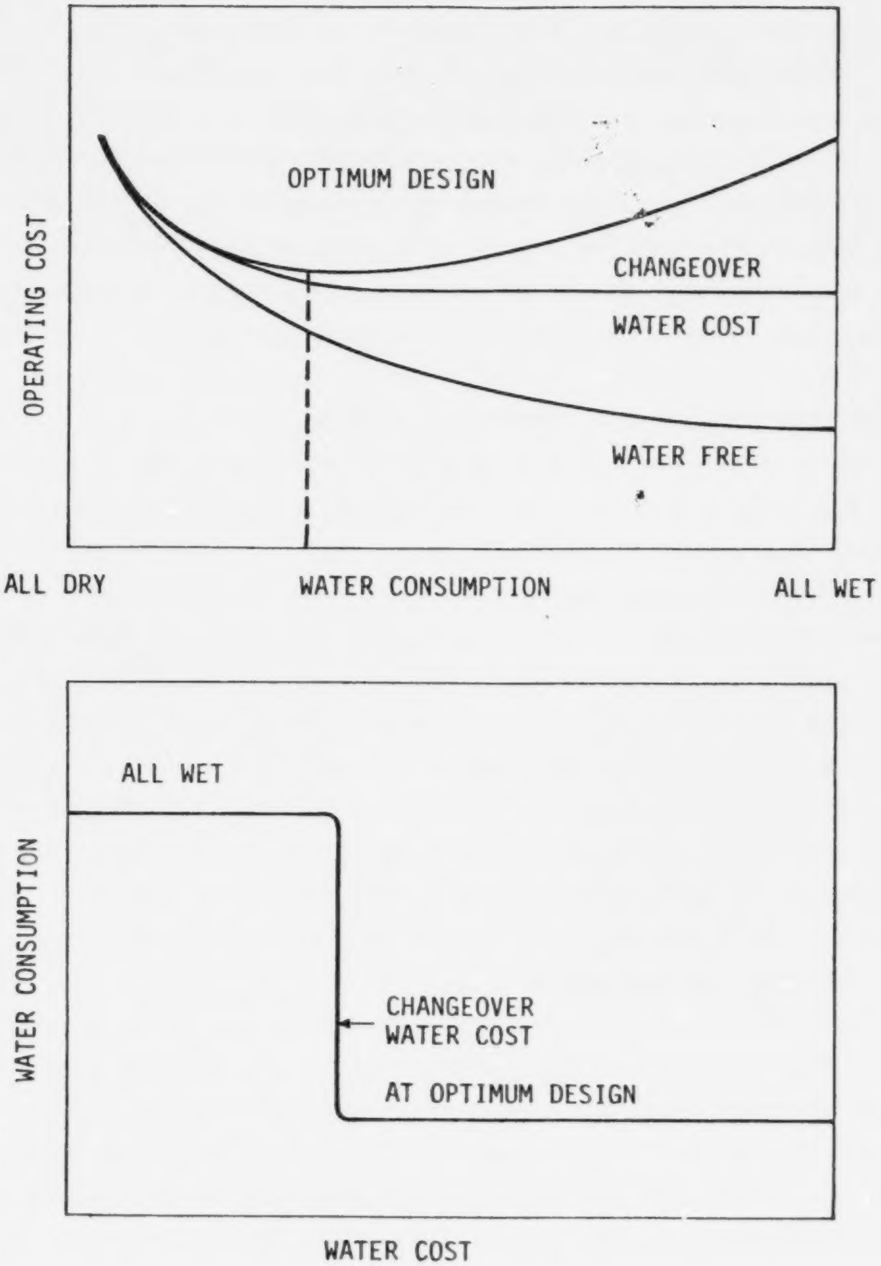

Figure 2-18. Operating costs and water consumption of wet/dry cooling system.

by 78 to 88 percent. However, some care should be exercised in interpreting this result since this reduction is based on a yearly average and the wet/dry system consumes water during periods of peaking in the summer months. In Reference 5, United Engineers and Constructors, Inc. correctly point out that although the annual makeup is small, the maximum flow rate over the peaking periods can be large. For example, for Farmington, New Mexico, a wet/dry tower consuming 10 percent of the annual water consumed for an all wet tower, will have a maximum flow rate of almost 60 percent of that required by an all wet system, resulting possibly in the building of impoundments since the stream flows may not be high enough in the summer to match the makeup requirements.

2.2 TURBINE CONDENSERS IN COAL CONVERSION PLANTS

On Figure 2-19 is shown a parallel dry/wet cooling system for a turbine condenser. The following calculations are intended to determine what fraction of the cooling load should be designed wet and what fraction should be designed dry; also, the water consumption is to be determined. Dry cooling has the advantage over wet cooling in that water is not used. It has the disadvantage of a higher capital investment and a higher condenser temperature. The higher condenser temperature means a lower efficiency for the turbine; that is, more energy as steam is consumed by the turbine for each kw-hr of shaft work performed.

Before an economic analysis can be made, a physical analysis is necessary. To obtain the desired information the cooling system is first designed and then its operation is analyzed, month by month, for a year. Finally, the economic analysis is made, and this depends on the cost of water.

2.2.1 Turbine Characteristics

In a steam turbine drive system the steam rate required by the turbine to produce a certain shaft power output depends on the inlet steam condition, the condenser pressure and the turbine efficiency. Usually the higher the inlet steam pressure and temperature, the higher will be the thermal efficiency of the system. In the present application where the steam is partially produced by waste heat recovery, the usual steam pressure is in the range of 715 to 915 psia, and the superheated temperature in the range of 600°F to 900°F. Also, in the present application where the steam turbine drive is used mainly for

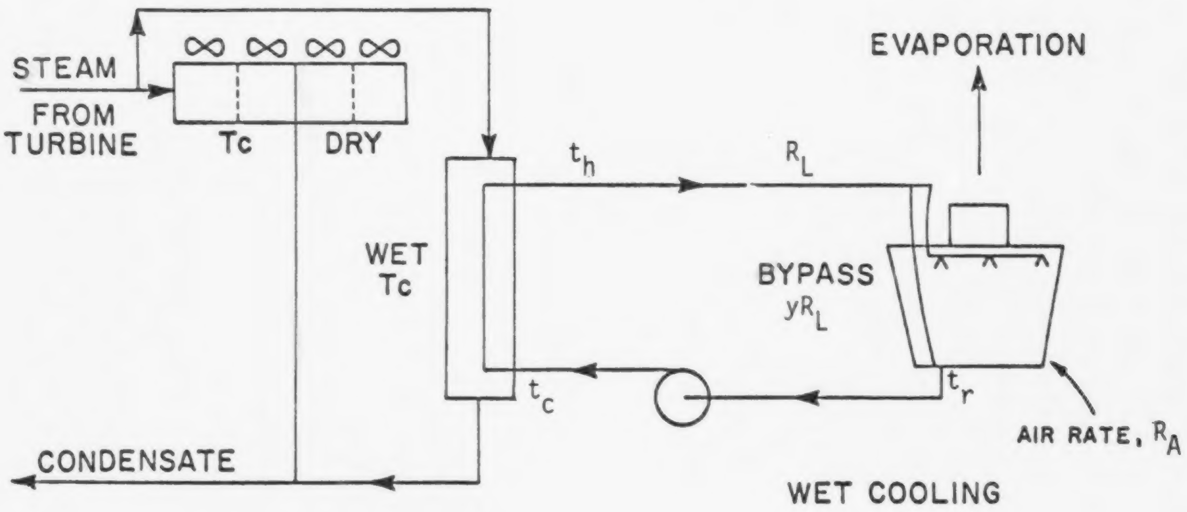
STEAM
FROM TURBINE
Tc
DRY
WET
Tc
CONDENSATE
t_h
R_L
EVAPORATION
BYPASS
yR_L
t_c
t_r
AIR RATE, R_A
WET COOLING

Figure 2-19. Turbine condenser cooling systems.

gas compression purposes, the type of turbine drive used usually has a maximum efficiency of about 80 percent when the condenser pressure is in the range of 3 to 5 in. Hg absolute. The corresponding steam saturation temperatures for the two condenser pressures are 115°F and 134°F respectively. Above 134°F, efficiency falls. We have assumed that below 115°F, the efficiency also falls. This is a function of the exhaust losses and may not be true for all turbines. However, usually there is no positive advantage in cooling below 115°F, so the procedure adopted in this study, which is never to cool below 115°F, is reasonably generally applicable when cooling water is scarce.

The heat rates required when the condenser temperature is in the range of 115°F to 134°F have been calculated for the various inlet steam conditions mentioned and are plotted in Figure 2-20. The calculations were made using an overall turbine efficiency of 80 percent including the bearing efficiency. The results in Figure 2-20 show that the steam rates for the four inlet steam conditions are quite close and that they can be represented by a single straight line going from a steam rate value of 11,700 Btu/kw-hr at the condenser temperature of 115°F to a value of 12,200 Btu/kw-hr at the condenser temperature of 134°F.

The increase in steam rate with condenser temperature indicates that there is a certain fuel penalty to be considered in evaluating the cost of various cooling systems.

The condenser cooling loads when the condenser temperature is in the range of 115°F to 134°F have also been calculated for the four inlet steam conditions mentioned and are plotted in Figure 2-21. The results indicate that the condenser loads for the four inlet steam conditions are also quite close and that they can be represented by a single straight line, going from a value of 8,200 Btu/kw-hr at the condenser temperature of 115°F to a value of 8,700 Btu/kw-hr at the condenser temperature of 134°F. This typical line will be used for condenser load calculations when the economics of condenser cooling systems are evaluated.

In analytical form the turbine heat rate is

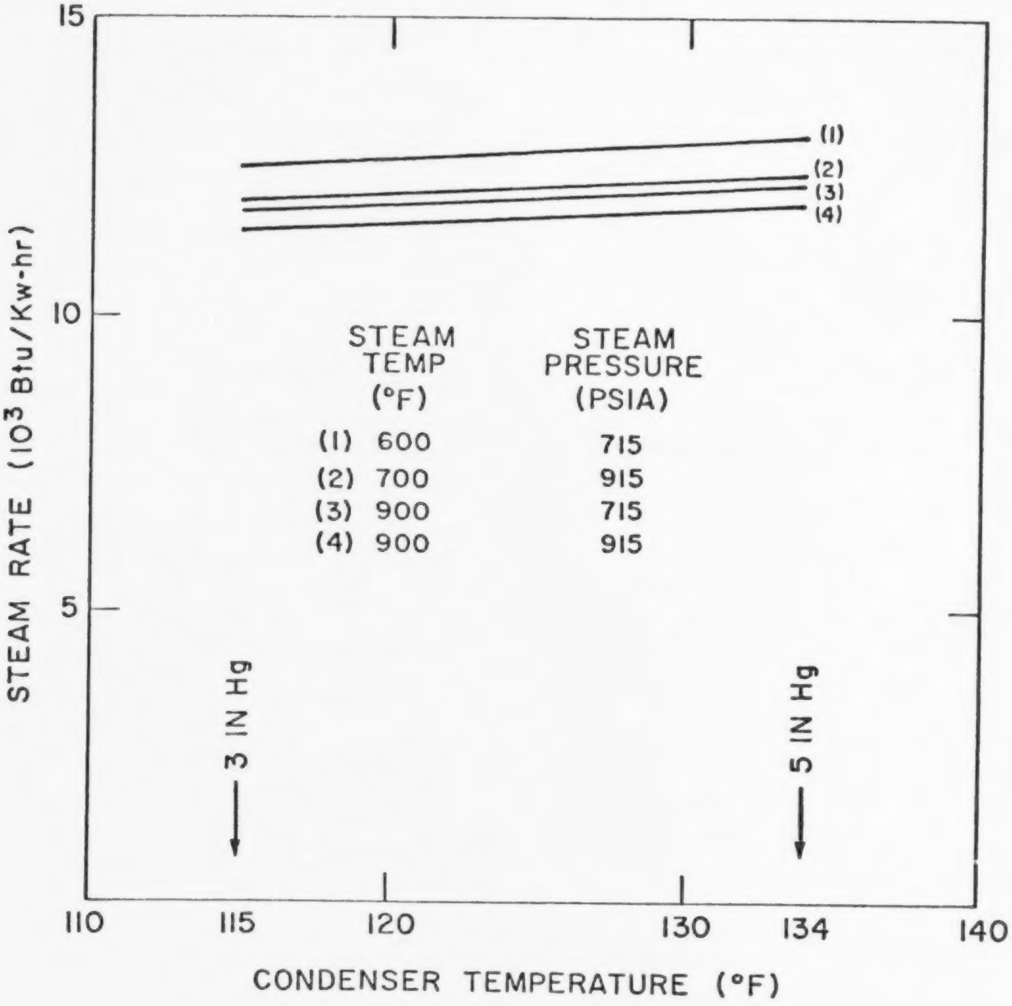

Figure 2-20. Turbine heat rates at full load.

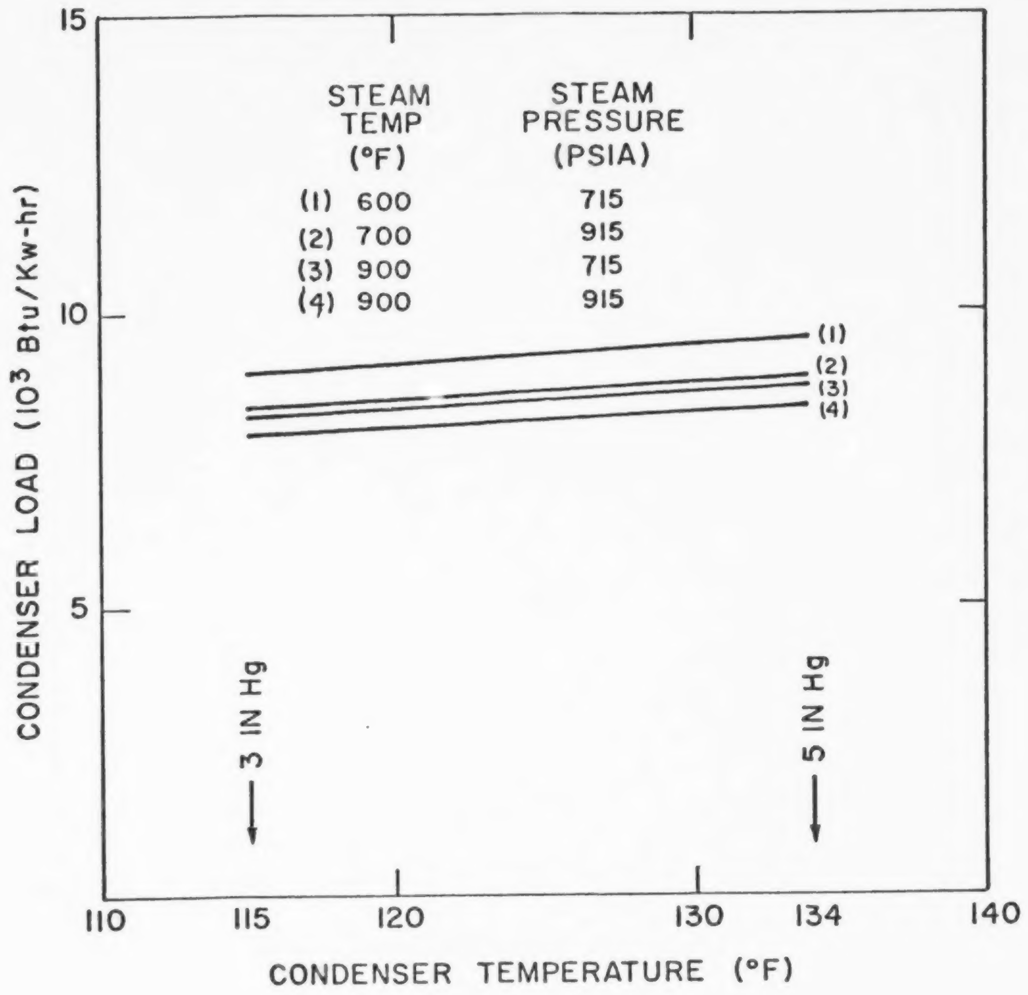

Figure 2-21. Turbine condenser cooling requirements at full load.

$$Q_H \text{ (Btu/kw-hr)} = 11{,}700 + 500 \left[\frac{T_C - 115}{134 - 115} \right]$$

$$= 8{,}674 + 26.32\, T_C, \text{ for } 115 \leq T_C \leq 134 \qquad (1)$$

and the condenser cooling load is

$$Q \text{ (Btu/kw-hr)} = 5{,}174 + 26.32\, T_C, \text{ for } 115 \leq T_C \leq 134 \qquad (2)$$

The nomenclature is shown on Table 2-8 shown with other tables collected at the end of this section.

2.2.2 Design Conditions

Design ambient conditions are given on Table 2-9 with complete monthly average ambient conditions. The condenser design condition is a condensing temperature of 134°F. This is a high design temperature chosen because the design ambient conditions are, on the average, not exceeded more than ten hours in a year. The design conditions for circulating cooling water are a hot water temperature, t_h, of 119°F which is a reasonable and usual 15°F below the design condensing temperature, and cold water temperature, t_c, of 94°F. The cold water temperature means that the circulating pumps must be sized for a 25°F rise which is usually found to be economical.

If x is the fraction of condenser load which is dry at design condition,

$$Q_{D,d} = 8{,}700x \qquad (3)$$

The dry condenser area, A_D is given by

$$Q_{D,d} = U_D A_D \text{ (LMTD)}_D \qquad (4)$$

where

$$\text{LMTD}_D = \frac{(T_C - T_{D,c}) - (T_C - T_{D,h})}{\ln \left\{ \frac{T_C - T_{D,c}}{T_C - T_{D,h}} \right\}} \qquad (5)$$

The temperature of the heated air leaving the dry condenser is found from the empirical equation

$$T_{D,h} - T_{D,c} = 0.005\ U_D(T_C - T_{D,c}) \tag{6}$$

from which

$$(T_C - T_{D,c}) - (T_C - T_{D,h}) = 0.005\ U_D(T_C - T_{D,c}) \tag{7}$$

$$T_C - T_{D,h} = (T_C - T_{D,c})(1 - 0.005\ U_D) \tag{8}$$

so,

$$\mathrm{LMTD}_D = \frac{0.005\ U_D(T_C - T_{D,c})}{\ln\left\{\dfrac{T_C - T_{D,c}}{(T_C - T_{D,c})(1-0.005\ U_D)}\right\}}$$

$$= 0.005\ U_D(T_C - T_{D,c})/\left\{-\ln(1 - 0.005\ U_D\right\} \tag{9}$$

Values of U_D are given on Table 2-9a. Since the design condenser temperature is

$$T_{C,d} = 134 \tag{10}$$

the design log mean temperature difference, $\mathrm{LMTD}_{D,d}$, can be found from Equation (9) and the area from Equations (3) and (4).

2.2.3 Design of Wet Condenser and Cooling Tower

To design the cooling tower, information on the efficiency of the packing is needed. It must be remembered that our objective in designing a tower is not to build a tower but to determine its operation at off-design conditions. The choice of tower type and fill pattern is therefore not very important. For this study we have used the comprehensive graphical data given in Kelley's Handbook[6] based on 18 ft of air travel and 30 ft height of fill type H. The tower design parameter, which is given the symbol K_aY/L and is called "characteristic," is taken from Reference 6 for the condition

$$\text{"Wet Bulb"} = T_{W,d}$$

$$\text{"Range"} = t_h - t_c = 25°\text{F} \qquad (11)$$

$$\text{"Approach"} = t_c - T_{W,d} = 94 - T_{W,d} \qquad (12)$$

$T_{W,d}$ is the design air wet bulb temperature.

The equations which give the wet condenser area are

$$Q_{W,d} = 8700(1 - x) = U_W A_W (\text{LMTD})_{W,d} \qquad (13)$$

$$(\text{LMTD})_{W,d} = \frac{(T_C - t_c) - (T_C - t_h)}{\ln\left\{\frac{T_C - t_c}{T_C - t_h}\right\}} \quad \text{(all design)}$$

$$= \frac{(134 - 94) - (134 - 119)}{\ln\left\{\frac{134 - 94}{134 - 119}\right\}}$$

$$= 25.5 \qquad (14)$$

The equations which give the rate of circulation of cooling water are

$$R_L(\text{lb/kw-hr}) = Q_{W,d}/25 \tag{15}$$

$$R_G(\text{gal/min})/\text{kw}) = R_L/(8.33)(60) = 0.002\ R_L \tag{16}$$

2.2.4 Off-Design Conditions, General

Calculations were made using monthly average ambient conditions for each month of a year beginning with the hottest and ending with the coldest. This is more convenient than considering the months in chronological order. The condenser temperature is first determined. If this is apparently below 115°F, then it is controlled at 115°F using the following control philosophy. First, the heat rejection load of the cooling tower is reduced by altering the pitch of the fans or by turning the fans off. When the ambient air temperature is sufficiently low, the evaporative tower is shut down and the heat load is carried by the dry cooler which controls the turbine back pressure by altering the fan blade pitch. When the cooling tower is shut down, the circulation of water is stopped. Water circulation is either full on or off. Throttling the circulation pumps leads to stagnation, fouling and scaling and is not practiced.

2.2.5 Determination of Condenser Temperature

Determination of the condenser temperature is a trial-and-error calculation made as follows.

1) A condenser temperature, T_C, is assumed.

2) The total cooling load, Q, is calculated from Equation (2).

3) The dry log mean temperature difference is calculated from Equation (5).

4) The dry cooling load is calculated from the equation

$$Q_D = U_D A_D (\text{LMTD})_D \tag{17}$$

5) The wet cooling load is calculated from the equation

$$Q_W = Q - Q_D \tag{18}$$

6) The cooling water temperatures are calculated from the wet cooling load. The "range" is given by the equation

$$t_h - t_c = Q_W/R_L \tag{19}$$

so,

$$t_c = t_h - Q_W/R_L \tag{20}$$

The rate of heat transfer in the wet condenser is given by

$$Q_W = U_W A_W (\mathrm{LMTD})_W \tag{21}$$

where

$$(\mathrm{LMTD})_W = (t_h - t_c)/\left\{\ln \frac{T_C - t_c}{T_C - t_h}\right\} \tag{22}$$

Algebraic manipulation of the above four equations gives

$$U_W A_W = Q_W/(\mathrm{LMTD})_W = R_L \ln\left\{\frac{T_C - t_c}{T_C - t_h}\right\} \tag{23}$$

or

$$\ln\left\{\frac{T_C - t_h + Q_W/R_L}{T_C - t_h}\right\} = U_W A_W/R_L \tag{24}$$

so,

$$t_h\left\{1 - \exp(U_W A_W/R_L)\right\} = T_C\left\{1 - \exp(U_W A_W/R_L)\right\} + Q_W/R_L \tag{25}$$

Equation (25) can be solved for t_h and Equation (20) for t_c.

7) Reference 6 is used to find whether, in fact, the cooling tower will give the water temperatures found for the prevailing wet bulb temperature T_w. Reference 6 gives the approach, $t_c - T_w$, when the wet bulb temperature, T_w, the range, $t_h - t_c$, and the tower characteristics are known. If t_c, calculated from the approach, is too high then the tower cannot do the job and a higher condenser temperature must be tried.

8) The fan and pump energy needs are calculated from the equations

$$\text{Dry condenser fan energy } E_D = 0.0149\ A_D \tag{26}$$

$$\text{Cooling tower fan energy } E_W = 0.0089\ R_G \tag{27}$$

$$\text{Cooling water circulation pump energy } E_C = 0.0246\ R_G \tag{28}$$

These equations are used only when the condenser temperature is above 115°F. When the condenser temperature is controlled at 115°F, the equation given in later steps should be used.

9) To calculate the water consumption, the rate of air flow through the tower must be known. The ratio of water flow to air flow, R_L/R_A, is part of the design of the tower (see Reference 6) and is known. Since the water flow, R_L, is known, the air flow, R_A, is also known. Knowing the dry bulb and wet bulb temperatures the absolute humidity of the entering air, H_i lb water/lb dry air, can be read from a standard psychometric chart. When the dry and wet bulb temperatures are below 30°F, the absolute humidity of the entering air is taken to be zero. It is also possible to calculate the enthalpy of the entering air, i_i. Enthalpies of humid air are normally measured above 0°F for dry air and liquid water at 32°F

$$i_i = 0.24\ T_D + H_i[1075 + 0.45(T_D - 32)] \tag{29}$$

In Equation (29), 0.24 is the specific heat of dry air, 0.45 is the specific heat of water vapor and 1075 is the latent heat of vaporization of water at 32°F.

Next, the condition of the air exiting the tower can be found. The enthalpy of the exit air is

$$i_e = i_i + Q_W/R_A \tag{30}$$

because the circulating water transfers the wet cooling load to the air. Experience shows that the leaving air is within a few percentage points of saturation and it is sufficiently accurate to assume it to be saturated. In Reference 6 is given a table of saturated air enthalpies against temperature from which the temperature of the air leaving the tower can be read. The psychometric chart gives the humidity of the leaving air, H_e. The rate of water evaporation is

$$R_A(H_e - H_i) \text{ lb/kw-hr} \tag{31}$$

Equation (31) applies when the tower is not bypassed. When the tower is bypassed the modification given in Step 18 is used.

2.2.6 Operation with 115°F Condenser Temperature

When the condenser temperature is known, the calculation is as follows.

10) The total cooling load is 8,200 Btu/kw-hr.

11) The dry log mean temperature difference is given by the equation

$$LMTD_D = 0.005\ U_D(115 - T_{D,c}) / \left\{-\ln(1 - 0.005\ U_D)\right\} \tag{32}$$

12) The dry cooling load is given by Equation (17).

13) The wet cooling load is given by the equation

$$Q_W = 8{,}200 - Q_D \tag{33}$$

14) The hot temperature of the circulating cooling water, t_h, is given by Equation (25) and the cold temperature, t_c, by Equation (20). The cold temperature is the temperature of blended water entering the condenser, not the temperature at the bottom of the cooling tower. The tower is bypassed.

15) The temperature at the bottom of the cooling tower, t_r, is found from Reference 6. It is that temperature which makes both the range, $t_h - t_r$, and approach, $t_r - T_W$, correct at the same time. When the wet bulb temperature is very low such that it is no longer on the graphs, an arbitrary 37°F approach is chosen. This makes the tower bottom temperature 37° higher than the wet bulb temperature.

16) The fraction of the flow which bypasses the tower, y, is given by

$$yR_L t_h + (1 - y)R_L t_r = R_L t_c \quad (34)$$

$$y = \frac{t_c - t_r}{t_h - t_r} \quad (35)$$

If $y \geq 1$, we skip to Step 19.

17) The dry condenser fan energy is given by Equation (26). The cooling water circulation pump energy is given by Equation (28). The cooling tower fan energy is

$$E_W = 0.0089(1 - y)R_G \quad (36)$$

18) The water evaporation is calculated as in Step 9, except that the air rate is now $(1 - y)R_A$, where R_A is the design air rate.

19) If the ambient conditions are so cold that the cooling tower is completely bypassed, the rate of water evaporated is zero, the cooling tower fan energy is zero and the cooling water circulation pump energy is zero. The only quantity to be calculated is the dry condenser fan energy. To do this we first need to know the air temperature, T_D', at which the dry condenser will carry the whole load. This is given by

$$8200 = U_D A_D \times 0.005\, U_D (115 - T_D') / \left\{ -\ln(1 - 0.005\, U_D) \right\} \quad (37)$$

$$115 - T_D' = \frac{-8200 \ln(1 - 0.005\, U_D)}{0.005\, U_D^2\, A_D} \quad (38)$$

The fan factor, F, is read from the vertical scale of Figure 2-22 when the horizontal scale point is $(T_D' - T_D)$. The dry condenser fan energy is

$$E_D = 0.0149\, FA_D \quad (39)$$

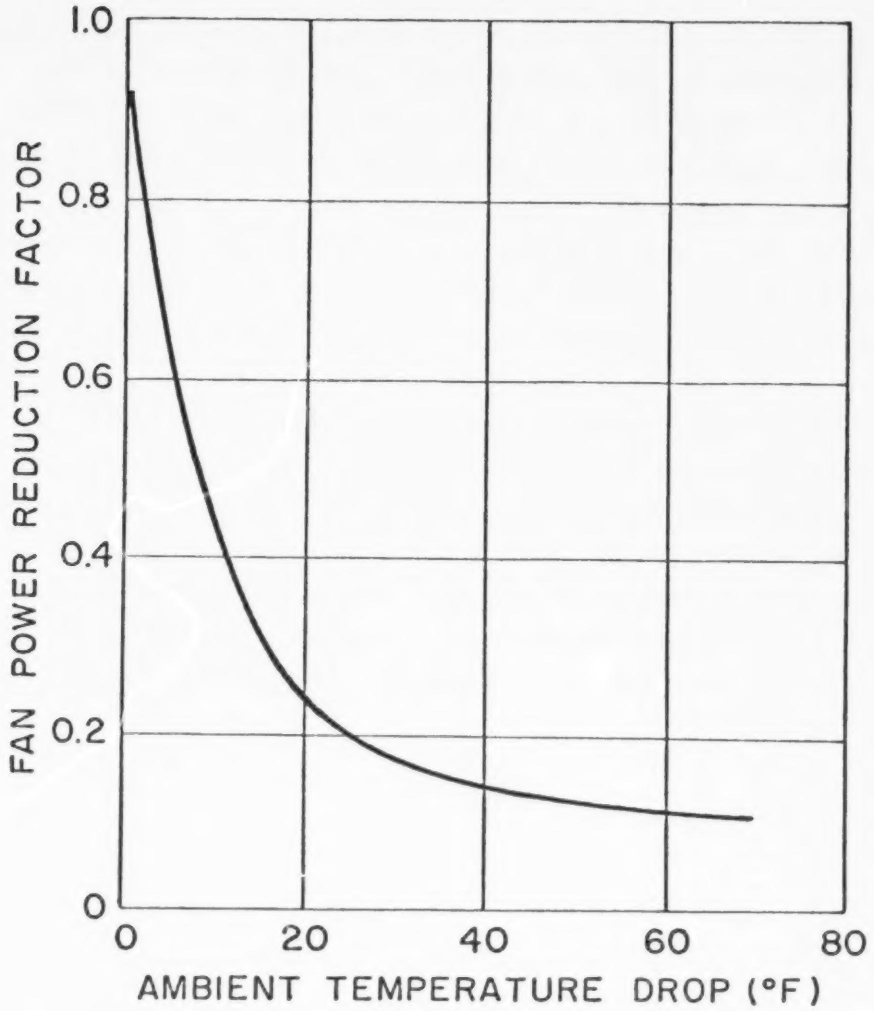

Figure 2-22. Fan power reduction factor for air coolers.

2.2.7 Results

The results of the month-by-month calculations are given for 0, 25, 50, 75 and 95 percent dry cooling at Farmington, New Mexico, at Casper, Wyoming and at Beulah, North Dakota on Tables 2-10, 2-11 and 2-12. Summaries are given on Table 2-12. To make the summaries, equal weight was given to each month: for example, the fan and pump energies from Tables 2-10 to 2-12 were totaled and divided by 12 to obtain the value entered on Table 2-13. The fuel penalty is that part of the turbine heat rate in excess of the minimum value, 11,700 Btu/kw-hr.

Because of the way the calculations were made, the hot and cold circulating water temperatures are both changed to control the system. Now, the cooling system may have other connections such as to process coolers, and the hot water returning to the tower may have a temperature derived from mixing all the returning streams. However, there is no other way of making calculations. If the cooling tower is not reserved exclusively for turbine condensers, then the calculations made are indicative but not a precise representation of reality. Fortunately the chosen configuration, when not all wet, is more than 90 percent dry and less than 10 percent wet. The wet condensers will only be turned on for a few months of the year, and even then they will carry such a small fraction of the load that control may not be required.

TABLE 2-8. NOMENCLATURE

A	condenser area, ft^2
E_C	cooling tower circulation pump energy, kw
E_D	dry condenser fan energy, kw
E_W	cooling tower fan energy, kw
F	dry condenser fan factor
H	absolute humidity of air, lb water/lb dry air
i	enthalpy of air, Btu/lb dry air
LMTD	log mean temperature difference, °F
P	compression power, kw
Q	condenser cooling load, Btu/kw-hr
Q_D	condenser dry cooling load, Btu/kw-hr
Q_H	turbine heat rate, Btu/kw-hr
Q_W	condenser wet cooling load, Btu/kw-hr
r	compression ratio
R_A	air rate through the tower, lb/hr
R_G	cooling water circulation rate, gpm/kw
R_L	cooling water circulation rate, lb/kw-hr
T_C	steam condensing temperature, °F
t_c	cold circulating water temperature, °F
T_D	air dry bulb temperature, °F
T'_D	air temperature at which dry condenser will carry whole load, °F
t_h	hot circulating water temperature, °F
t_r	temperature at bottom of cooling tower, °F
T_W	air wet bulb temperature, °F

(continued)

TABLE 2-8 (continued)

U	heat transfer coefficient, Btu/(hr)(ft^2)(°F)
x	fraction of cooling load carried dry
y	fraction of circulating water that bypasses the cooling tower

Suffixes

c	cold or entry temperature
C	condensing temperature
D	dry
d	design condition
e	exiting, or out
h	hot, or exit temperature
i	entering, or in
o	out, or discharge
W	wet
X	temperature between dry and wet series coolers between compression stages
1,2,3	compressor stages

TABLE 2-9. AVERAGE AMBIENT CONDITIONS

Month	Farmington, N. M.		Casper, Wyo.		Beulah, N. D.	
	DBT*	WBT**	DBT	WBT	DBT	WBT
1, January	26	23	24	20	8	7
2, February	33	28	26	22	15	13
3, March	42	33	32	27	24	21
4, April	49	37	41	34	43	37
5, May	60	45	54	44	56	47
6, June	70	51	65	51	65	57
7, July	76	58	71	55	72	62
8, August	73	57	70	53	70	60
9, September	64	49	59	46	58	50
10, October	51	41	47	38	46	39
11, November	39	32	32	47	28	25
12, December	27	24	30	25	18	17
Design	98	65	96	60	102	71

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*DBT = dry bulb temperature (°F).
**WBT = wet bulb temperature (°F).

TABLE 2-9a. HEAT TRANSFER COEFFICIENTS, FAN AND PUMP ENERGIES

	U[Btu/(hr)(ft^2)(°F)]	
	Dry	Wet
Condensing steam from turbine drives:	120	170

	Dry		Wet	
	Air	Hydrogen	Air	Hydrogen
Cooling a compressed gas:				
10 psig	10	30	12	35
50 psig	20	45	20	75
100 psig	30	65	40	100
300 psig	40	85	60	135
$\geq$ 500 psig	50	95	70	150

Dry cooler fans: kw = 0.0112 x area ($U \leq 50$)
= 0.0130 x area ($100 > U > 50$)
= 0.0149 x area ($U \geq 100$)

Cooling tower fans: kw = 0.0089 x gpm circulated

Circulating water pumps: kw = 0.0246 x gpm circulated

TABLE 2-10. CALCULATIONS ON STEAM TURBINE CONDENSERS AT FARMINGTON, NEW MEXICO

Design Conditions: Fraction designed dry 0.

Dry condenser area 0 ft^2/kw, wet condenser area 2.0069 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12, circulation rate 348 lb/kw-hr, 0.696 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	117	119	124	126	131	129	125	120	116	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,753	11,806	11,938	11,990	12,122	12,069	11,964	11,832	11,727	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,253	8,306	8,437	8,490	8,622	8,569	8,464	8,332	8,227	8,200
Dry condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Wet condenser load (Btu/kw-hr)	8,200	8,200	8,253	8,306	8,437	8,490	8,622	8,569	8,464	8,332	8,227	8,200
Hot water temperature (°F)	101	101	103	105	109	111	116	114	110	106	102	101
Cold water temperature (°F)	77	77	79	81	85	87	91	90	86	82	78	77
Tower bottom temperature (°F)	60	65	79	81	85	87	91	90	86	82	78	61
Fraction circulating water that bypasses tower	0.41	0.33	0	0	0	0	0	0	0	0	0	0.40
Dry fan power ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Coolg tower fan pwr ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	3.65	5.39	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	3.72
Circulating pump pwr ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
Water evaporated (lb/kw-hr)	5.52	5.57	5.41	5.67	6.06	6.45	6.69	6.601	6.23	5.78	5.36	5.36

(continued)

TABLE 2-10. (continued)

Design Conditions: Fraction designed dry 0.25.

Dry condenser area 0.7689 ft^2/kw, wet condenser area 1.5051 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12, circulation rate 261 lb/kw-hr, 0.522 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	119	123	122	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,806	11,911	11,885	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,306	8,411	8,385	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	5,377	4,954	4,410	3,987	3,322	2,960	2,839	2,960	3,081	3,867	4,592	5,316
Wet condenser load (Btu/kw-hr)	2,823	3,246	3,790	4,213	4,877	5,346	5,572	5,425	5,119	4,334	3,609	2,884
Hot water temperature (°F)	109	108	106	105	104	107	110	109	103	105	107	108
Cold water temperature (°F)	98	95	92	89	85	86	89	89	84	88	93	97
Tower bottom temperature (°F)	60	65	70	84	83	86	89	89	83	82	69	61
Fraction circulating water that bypasses tower	0.78	0.70	0.33	0.24	0.10	0	0	0	0.05	0.26	0.75	0.77
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5	11.5
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	1.02	1.39	3.11	3.53	4.18	4.64	4.64	4.64	4.41	3.44	1.16	1.06
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Water evaporated (lb/kw-hr)	1.96	2.23	2.45	2.84	3.46	4.36	4.70	4.16	3.70	2.94	2.61	2.01

(continued)

TABLE 2-10. (continued)

Design Conditions: Fraction designed dry 0.50.

Dry condenser area 1.5378 ft^2/kw, wet condenser area 1.0035 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12, circulation rate 174 lb/kw-hr, 0.348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	117	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,753	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,253	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	7,975	6,646	5,438	4,954	5,075	6,163	7,734	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	224	1,554	2,762	3,299	3,125	2,037	466	0	0
Hot water temperature (°F)	--	--	--	114	110	105	106	104	108	113	--	--
Cold water temperature (°F)	--	--	--	113	101	90	87	86	96	111	--	--
Tower bottom temperature (°F)	--	--	--	92	88	85	87	85	86	88	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	0.95	0.59	0.75	0	0.05	0.45	0.92	1.0	1.0
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	5.25	7.79	14.77	22.9	22.9	22.9	22.9	22.9	22.9	22.9	11.57	4.81
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0.15	1.27	0.77	3.10	2.94	1.70	0.25	0	0
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	8.56	8.56	8.56	8.56	8.56	8.56	8.56	0	0
Water evaporated (lb/kw-hr)	0	0	0	0.16	1.06	2.18	2.56	2.45	1.49	0.24	0	0

(continued)

TABLE 2-10. (continued)

Design Conditions: Fraction designed dry 0.75.

Dry condenser area 2.3069 ft^2/kw, wet condenser area 0.5017 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12,
circulation rate 87 lb/kw-hr, 0.174 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,157	7,069	7,613	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	43	1,131	587	0	0	0	0
Hot water temperature (°F)	--	--	--	--	--	115	107	111	--	--	--	--
Cold water temperature (°F)	--	--	--	--	--	114	94	104	--	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	88	92	89	--	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	0.96	0.13	0.68	1.0	1.0	1.0	1.0
Dry fan power ($10^{-3}\frac{\text{kw-hr}}{\text{kw-hr}}$)	4.50	4.98	6.19	7.97	15.5	34.4	34.4	34.4	21.21	8.83	4.85	4.54
Coolg tower fan pwr ($10^{-3}\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0.06	1.35	0.49	0	0	0	0
Circulating pump pwr ($10^{-3}\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	4.28	4.28	4.28	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0.035	0.93	0.453	0	0	0	0

(continued)

TABLE 2-10. (continued)

Design Conditions: Fraction designed dry 0.95.

Dry condenser area 2.922 ft^2/kw, wet condenser area 0.1003 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.24, water/gas rates 2.12, circulation rate 17.4 lb/kw-hr, 0.0348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Hot water temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Cold water temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Dry fan power (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	5.22	5.70	6.26	7.27	10.8	20.2	33.18	25.69	13.63	7.71	6.05	5.27
Coolg tower fan pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Circulating pump pwr (10^{-3} $\frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0

TABLE 2-11 CALCULATIONS ON STEAM TURBINE CONDENSERS AT CASPER, WYOMING

Design Conditions: Fraction designed dry 0.

Dry condenser area 0 ft^2/kw, wet condenser area 2.0069 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24,
circulation rate 348 lb/kw-hr, 0.696 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	116	122	127	130	131	130	129	122	116	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,727	11,885	12,016	12,096	12,122	12,096	12,069	11,885	11,727	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,227	8,385	8,516	8,596	8,622	8,596	8,569	8,385	8,227	8,200
Dry condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Wet condenser load (Btu/kw-hr)	8,200	8,200	8,227	8,385	8,516	8,596	8,622	8,596	8,569	8,385	8,227	8,200
Hot water temperature (°F)	101	101	102	108	112	115	116	115	114	109	102	101
Cold water temperature (°F)	77	77	78	83	88	90	91	90	90	83	78	77
Tower bottom temperature (°F)	57	59	78	83	88	90	91	90	90	83	78	62
Fraction circulating water that bypasses tower	0.45	0.43	0	0	0	0	0	0	0	0	0	0.38
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0	0	0	0	0	0	0
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	3.40	3.53	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	6.19	3.84
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12
Water evaporated (lb/kw-hr)	5.54	5.57	5.28	5.47	6.00	6.39	6.56	6.52	6.22	5.78	5.28	5.49

(continued)

TABLE 2-11(continued)

Design Conditions: **Fraction designed dry 0.25.**

Dry condenser area 0.728 ft^2/kw, wet condenser area 1.5051 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24,
circulation rate 261 lb/kw-hr, 0.522 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	118	122	121	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,780	11,885	11,859	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,279	8,385	8,358	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	5,206	5,091	4,747	4,233	3,203	3,032	2,917	2,917	3,203	3,890	4,748	4,862
Wet condenser load (Btu/kw-hr)	2,995	3,109	3,452	3,967	4,997	5,248	5,468	5,441	4,997	4,311	3,452	3,338
Hot water temperature (°F)	108	108	107	106	104	106	109	108	104	105	107	107
Cold water temperature (°F)	97	96	94	91	84	86	88	88	84	89	94	95
Tower bottom temperature (°F)	57	59	64	71	84	86	88	88	84	84	64	62
Fraction circulating water that bypasses tower	0.78	0.75	0.70	0.57	0	0	0	0	0	0.24	0.70	0.73
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	1.02	1.16	1.39	2.00	4.65	4.65	4.65	4.65	4.65	3.53	1.39	1.25
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Water evaporated (lb/kw-hr)	2.07	2.14	2.40	2.71	3.52	3.91	4.20	4.06	3.56	2.91	2.40	2.33

(continued)

TABLE 2-11 (continued)

Design Conditions: Fraction designed dry 0.75.

Dry condenser area 2.185 ft^2/kw, wet condenser area 0.5017 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24, circulation rate 87 lb/kw-hr, 0.174 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	7,554	7,726	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	0	646	474	0	0	0	0
Hot water temperature (°F)	--	--	--	--	--	--	111	112	--	--	--	--
Cold water temperature (°F)	--	--	--	--	--	--	103	106	--	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	--	89	89	--	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	1.0	0.64	0.74	1.0	1.0	1.0	1.0
Dry fan power $(10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr})$	4.30	4.43	4.85	6.32	11.69	27.05	32.5	32.5	16.38	7.72	4.85	4.66
Coolg tower fan pwr $(10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr})$	0	0	0	0	0	0	0.56	0.40	0	0	0	0
Circulating pump pwr $(10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr})$	0	0	0	0	0	0	4.28	4.28	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0	0.48	0.36	0	0	0	0

(continued)

TABLE 2-11 (continued)

Design Conditions: Fraction designed dry 0.50.

Dry condenser area 1.4568 ft^2/kw, wet condenser area 1.0035 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24, circulation rate 174 lb/kw-hr, 0.348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	6,982	5,723	5,036	5,151	6,410	7,784	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	1,218	2,477	3,164	3,049	1,790	416	0	0
Hot water temperature (°F)	--	--	--	--	111	106	104	104	109	114	--	--
Cold water temperature (°F)	--	--	--	--	104	92	86	87	99	111	--	--
Tower bottom temperature (°F)	--	--	--	--	87	86	86	86	87	90	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	0.71	0.30	0	0.06	0.55	0.91	1.0	1.0
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	5.42	6.07	8.79	17.97	21.7	21.7	21.7	21.7	21.7	21.7	8.79	7.73
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0.90	2.17	3.10	2.91	1.39	0.29	0	0
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	8.56	8.56	8.56	8.56	8.56	8.56	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0.87	1.86	2.40	2.36	1.29	0.009	0	0

(continued)

TABLE 2-11 (continued)

Design Conditions: Fraction designed dry 0.95.

Dry condenser area 2.7680 ft^2/kw, wet condenser area 0.1003 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.17, water/gas rates 2.24, circulation rate 17.4 lb/kw-hr, 0.0348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Hot water temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Cold water temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Tower bottom temperature (°F)	--	--	--	--	--	--	--	--	--	--	--	--
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Dry fan power ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	4.95	4.99	5.32	6.06	8.66	15.71	24.29	22.11	10.81	6.89	5.32	4.65
Coolg tower fan pwr ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Circulating pump pwr ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0

TABLE 2-12 CALCULATIONS ON STEAM TURBINE CONDENSERS AT BEULAH, NORTH DAKOTA

Design Conditions: Fraction designed dry 0.

Dry condenser area 0 ft^2/kw, wet condenser area 2.007 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.30, water/gas rates 1.85, circulation rate 348 lb/kw-hr, 0.696 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	119	124	126	129	127	124	119	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,806	11,938	11,990	12,069	12,017	11,938	11,806	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,306	8,438	8,490	8,569	8,517	8,438	8,306	8,200	8,200
Dry condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Wet condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,306	8,438	8,490	8,569	8,517	8,438	8,306	8,200	8,200
Hot water temperature (°F)	101	101	101	105	109	111	114	112	109	105	101	101
Cold water temperature (°F)	77	77	77	81	84	87	90	88	85	81	77	77
Tower bottom temperature (°F)	45	52	61	81	85	87	90	88	85	81	65	55
Fraction circulating water that bypasses tower	0.57	0.51	0.40	0	0	0	0	0	0	0	0.33	0.48
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0	0	0	0	0	0	0	0	0	0	0	0
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	2.66	3.03	3.72	6.19	6.19	6.19	6.19	6.19	6.19	6.19	4.15	3.22
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12	17.12
Water evaporated (lb/kw-hr)	4.42	4.70	4.89	5.64	6.26	6.40	6.64	6.58	6.11	5.64	5.08	4.70

(continued)

TABLE 2-12 (Continued)

Design Conditions: Fraction designed dry 0.25.

Dry condenser area 0.865 ft^2/kw, wet condenser area 1.505 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.30, water/gas rates 1.85, circulation rate 261 lb/kw-hr, 0.522 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,806	11,753	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	7,273	6,797	6,185	4,894	4,010	3,398	3,195	3,194	3,874	4,690	5,914	6,593
Wet condenser load (Btu/kw-hr)	927	1,403	2,015	3,306	4,190	4,801	5,111	5,059	4,326	3,510	2,286	1,607
Hot water temperature (°F)	113	112	110	107	105	104	107	105	105	107	110	111
Cold water temperature (°F)	109	106	103	95	89	86	87	86	88	93	101	105
Tower bottom temperature (°F)	45	52	61	81	83	86	87	86	83	81	65	55
Fraction circulating water that bypasses tower	0.94	0.90	0.86	0.54	0.27	0	0	0	0.23	0.46	0.80	0.89
Dry fan power (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
Coolg tower fan pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	0.28	0.46	0.65	2.14	3.39	4.65	4.65	4.65	3.58	2.51	0.93	0.51
Circulating pump pwr (10^{-3} $\frac{\text{kw-hr}}{\text{kw-hr}}$)	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
Water evaporated (lb/kw-hr)	0.28	0.56	1.13	2.20	3.00	3.67	4.02	4.00	3.13	2.40	1.27	0.78

(continued)

TABLE 2-12 (Continued)

Design Conditions: Fraction designed dry 0.50.

Dry condenser area 1.730 ft^2/kw, wet condenser area 1.003 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.30, water/gas rates 1.85, circulation rate 174 lb/kw-hr, 0.348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,020	6,797	5,845	6,117	7,749	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	180	1,403	2,355	2,083	451	0	0	0
Hot water temperature (°F)	-	-	-	-	114	110	107	108	113	-	-	-
Cold water temperature (°F)	-	-	-	-	113	102	93	96	111	-	-	-
Tower bottom temperature (°F)	-	-	-	-	86	86	88	85	86	-	-	-
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	0.96	0.67	0.26	0.48	0.93	1.0	1.0	1.0
Dry fan power (10^{-3} $\frac{kw-hr}{kw-hr}$)	3.1	4.6	4.9	10.3	25.8	25.8	25.8	25.8	25.8	10.3	5.1	4.7
Coolg tower fan pwr (10^{-3} $\frac{kw-hr}{kw-hr}$)	0	0	0	0	0.12	1.02	2.29	1.61	0.22	0	0	0
Circulating pump pwr (10^{-3} $\frac{kw-hr}{kw-hr}$)	0	0	0	0	8.56	8.56	8.56	8.56	8.56	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0.40	1.22	1.91	1.74	0.56	0	0	0

(continued)

TABLE 2-12 (Continued)

Design Conditions: Fraction designed dry 0.75.

Dry condenser area 2.595 ft^2/kw, wet condenser area 0.502 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.30, water/gas rates 1.85, circulation rate 87 lb/kw-hr, 0.174 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Wet condenser load (Btu/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0
Hot water temperature (°F)	-	-	-	-	-	-	-	-	-	-	-	-
Cold water temperature (°F)	-	-	-	-	-	-	-	-	-	-	-	-
Tower bottom temperature (°F)	-	-	-	-	-	-	-	-	-	-	-	-
Fraction circulating water that bypasses tower	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Dry fan power ($10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr}$)	4.64	5.02	5.60	6.94	10.0	15.4	38.7	31	7.0	6.95	5.80	4.64
Coolg tower fan pwr ($10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Circulating pump pwr ($10^{-3} \frac{kw\text{-}hr}{kw\text{-}hr}$)	0	0	0	0	0	0	0	0	0	0	0	0
Water evaporated (lb/kw-hr)	0	0	0	0	0	0	0	0	0	0	0	0

(continued)

TABLE 2-12 (Concluded)

Design Conditions: Fraction designed dry 0.95.

Dry condenser area 3.287 ft^2/kw, wet condenser area 0.100 ft^2/kw.

Cooling tower information: characteristic, KaY/L = 1.30, water/gas rates 1.85, circulation rate 17.4 lb/kw-hr, 0.0348 gpm/kw.

Month	1	2	3	4	5	6	7	8	9	10	11	12
Condenser temperature (°F)	115	115	115	115	115	115	115	115	115	115	115	115
Turbine heat rate (Btu/kw-hr)	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700	11,700
Total condenser load (Btu/kw-hr)	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200	8,200
Dry condenser load (Btu/kw-hr)	---------------------			NOT REQUIRED AS								
Wet condenser load (Btu/kw-hr)				WATER CONSUMPTION								
Hot water temperature (°F)												
Cold water temperature (°F)				ALREADY NEGLIGIBLE								
Tower bottom temperature (°F)				FOR 75% DESGINED DRY.								
Fraction circulating water that bypasses tower												
Dry fan power ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)												
Coolg tower fan pwr ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)												
Circulating pump pwr ($10^{-3}\ \frac{kw\text{-}hr}{kw\text{-}hr}$)												
Water evaporated (lb/kw-hr)												

TABLE 2-13 SUMMARY OF WET/DRY CONDENSER COOLING CALCULATIONS

Farmington, New Mexico

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser area ft^2/kw	2.92	2.31	1.54	0.77	0
Wet condenser area ft^2/kw	0.100	0.50	1.00	1.51	2.01
Circulation rate gpm/kw	0.0348	0.174	0.348	0.52	0.696
Avg fuel penalty Btu/kw-hr	0	0	4.417	41.833	158.42
Avg fan & pump energy kw-hr/kw-hr	0.012	0.016	0.023	0.027	0.023
Avg water consumption gal/kw-hr	0*	0.014	0.101	0.374	0.707

Casper, Wyoming

Fraction designed dry	0.95	0.75	0.50	0.25	0
Dry condenser area ft^2/kw	2.77	2.19	1.46	0.728	0
Wet condenser area ft^2/kw	0.100	0.50	1.00	1.51	2.01
Circulation rate gpm/kw	0.0348	0.174	0.348	0.522	0.696
Avg fuel penalty Btu/kw-hr	0	0	0	35.33	193.58
Avg fan & pump energy kw-hr/kw-hr	0.010	0.014	0.021	0.027	0.023
Avg water consumption gal/kw-hr	0*	0.008	0.088	0.362	0.701

Beulah, North Dakota

Fraction designed dry	0.75	0.50	0.25	0
Dry condenser area ft^2/kw	2.595	1.730	0.865	0
Wet condenser area ft^2/kw	0.502	1.003	1.505	2.007
Circulation rate gpm/kw	0.174	0.348	0.522	0.696
Avg fuel penalty Btu/kw-hr	0	0	13.25	138.7
Avg fan & pump energy kw-hr/kw-hr	0.012	0.018	0.028	0.022
Avg water consumption gal/kw-hr	0	0.058	0.265	0.071

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*Less than 0.001.

2.3 AIR COMPRESSORS IN COAL CONVERSION PLANTS

To study the effect of series dry-wet coolers on interstage cooling in gas compressors two compressors have been studied, an air compressor and a hydrogen compressor. The study on the hydrogen compressor is given in the following section. The study on the air compressor follows.

2.3.1 Design Conditions

Air is compressed from ambient temperature and 15 psia to 90 psia and 104°F (or cooler), in which condition air enters the separation plant to be separated into nitrogen and oxygen. Air compressors are used in all plants, and they are the biggest compressors in the gas plants. The compressor is shown on Figure 2-23. It is a three-stage compressor with a compression ratio of 1.817 per stage. The temperatures T_X and T_i = 109°F are design conditions. The stage outlet temperatures are calculated from the equation

$$T_o = T_i \, r^{(n-1)/n} \tag{40}$$

where

T_o, T_i are outlet and inlet temperatures, °R, (°R = 460 + °F)

r is the compression ratio

$(n-1)/n = 0.371$ for air

The only number which must be chosen is T_X, the temperature between the air cooler and the wet cooler. The following calculations are intended to determine what T_X should be.

To begin, it is necessary to know the power consumed by a gas compressor.

The general equations for the horsepower needed to drive a gas compressor are[7]:

$$HP = WH/33{,}000e \tag{41}$$

$$H = \left(\frac{Z_s + Z_d}{2}\right)\left(\frac{1{,}545}{M_w}\right) T_s \left[\frac{r^{(n-1)/n} - 1}{(n-1)/n}\right] \tag{42}$$

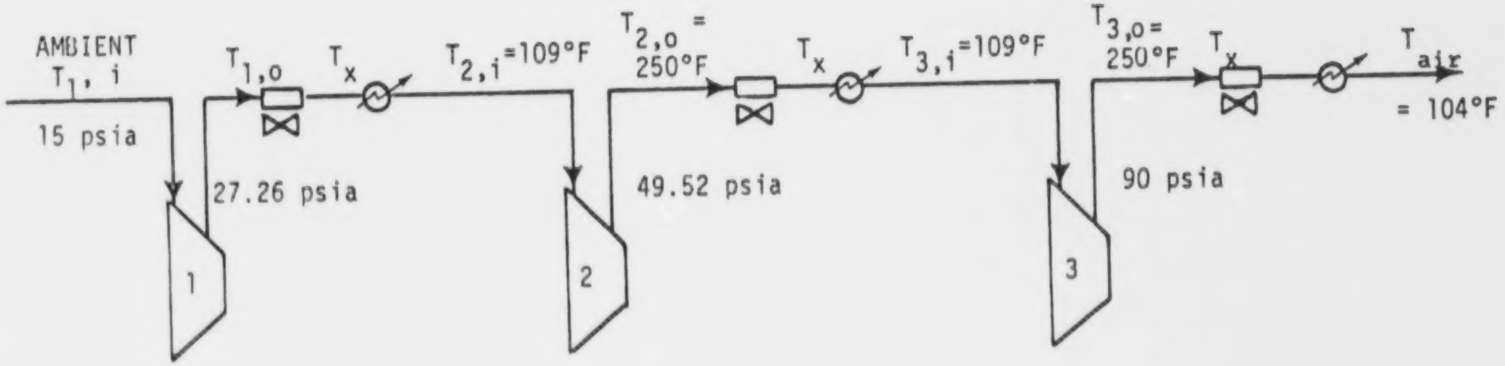
AMBIENT
$T_{1,i}$
15 psia
$T_{1,o}$
27.26 psia
T_x
$T_{2,i}$=109°F
1
$T_{2,o}$ = 250°F
49.52 psia
T_x
$T_{3,i}$=109°F
2
$T_{3,o}$= 250°F
90 psia
T_x
3
T_{air} = 104°F

Figure 2-23. Air compressor design conditions.

$$(n-1)/n = (k-1)/ke \tag{43}$$

HP is horsepower

W is gas flow in lb/min

H is polytrophic head (ft-lb)/lb

e is polytrophic efficiency

Z_s, Z_d are compressibility factors for suction and discharge

M_w is molecular weight

T_s is suction temperature, °R(°R = 460 + °F)

r is the compression ratio

k is ratio of specific heats

For air, the appropriate values of the parameters are:

W - 16.67
e - 0.77
Z_s - 1.0
Z_d - 1.0
k - 1.40
M_w - 29
(n-1)/n - 0.371

The choice of W means that all calculations are based on 1,000 lb/hr of gas. Note that 1,000 lb/hr of air is equivalent to 233 lb/hr of oxygen.

The short equation, where P is the power in kw (= 1.341 HP), is:

$$P = 0.0702\ T_i (r^{0.371} - 1) \tag{44}$$

Monthly average and design ambient conditions are as previously given for turbine condenser calculations. Hot and cold water design temperatures are 119°F and 94°F as above, and the tower characteristics are as previously found. For interstage cooling the tower is assumed independent of the tower for the turbine condensers. This means a segregated cooling loop which is acceptable practice but not always done. The two cooling loops are assumed segregated in this study to limit the calculation and to aid in understanding the theory.

T_X is chosen and the areas of the various wet and dry coolers determined. The heat transfer coefficient varies with the gas pressure as shown on Table 2-10.

The load on the cooler, Btu/hr, is

$$(\text{gas rate, lb/hr})(T_{in} - T_{out})c_p \tag{45}$$

The gas rate is 1,000 lb/hr. The specific heat is sufficiently independent of temperature and pressure to be taken as constant. We have used

$$c_p(\text{air}) = 0.241 \tag{46}$$

so, the load

$$Q = 241(T_{in} - T_{out}) \tag{47}$$

The wet and dry cooler areas following each stage are calculated and tabulated. The calculation proceeds as follows.

1) For the design ambient temperature, calculate the first stage outflow temperature $T_{1,0}$ from Equation (40) which, for this compressor, is

$$T_{out} = 1.248\ T_{in} \tag{48}$$

2) Calculate the area of the air cooler from the equations

$$Q_D = U_D A_D(\text{LMTD})_D = 241(T_o - T_X) \tag{49}$$

$$\text{LMTD}_D = \frac{\text{GTD} - \text{LTD}}{\ln \frac{\text{GTD}}{\text{LTD}}} \tag{50}$$

where GTD is the greater of the temperature differences

$$(T_o - T_{D,h}) \text{ and } (T_X - T_{D,d})$$

and LTD is the lesser temperature differences. The nomenclature is given on Figure 2-23 and Table 2-8.

The hot temperature on the ambient side of the cooler is given by

$$T_{D,h} - T_{D,d} = 0.005\ U_D \left(\frac{T_o + T_X}{2} - T_{D,d} \right) \qquad (51)$$

All four temperatures are known and A_D can be found for each stage.

3) Calculate the area of the wet cooler from the equation

$$Q_w = U_w A_w (\text{LMTD})_w = 241\ (T_X - T_i) \qquad (52)$$

where LMTD_w is given by an equation similar to Equation (50) in which the temperature differences are

$$(T_X - t_h) \text{ and } (T_i - t_c)$$

The design conditions are: T_X as chosen, t_h = 119°F, T_i = 109°F, t_c= 94°F. The wet area is calculated for all stages.

4) The water circulation rates for each wet cooler are calculated from Equations (15) and (16). The total flow is the sum of the individual flows.

2.3.2 Off-Design Conditions

When turbine condensers were studied, there was actually a penalty for cooling too low. In this case there is a benefit for cooling to a lower, and still lower temperature--namely, the compression energy is decreased. At first sight the optimum strategy is not apparent: whether to control the inlet temperature to each stage or let it go as cold as possible. However, calculations show that maximum cooling is always preferable. An example can be given to show this. With the temperature between dry and wet cooling equal to 160°F in Farmington, New Mexico, the maximum cooling calculations using

Set No. 1 and presented in Section 2.1 show a cost of 65.54 ¢/1000 lb and a water evaporation rate of 1.929 gal/1000 lb. If water is turned off for months 1, 2, 3, 11 and 12, the cost goes up by 0.65 ¢/1000 lb and the water consumption goes down by 0.562 gal/1000 lb (Tables 2-13 and 2-14). This cost of water is $11.57/thousand gallons, which is too high.

2.3.3 Operation with Maximum Cooling

5) The calculation must begin at the entry to the first stage and proceed through each piece of equipment in series. First the exit temperature from Stage 1 is calculated.

6) Next, $T_{X,1}$ is calculated by simultaneous solution of Equations (49), (50) and (51). A trial-and-error solution is used. A value is assumed for T_X, $T_{D,h}$ is calculated from Equation (51) and $LMTD_D$ is calculated from Equation (50). The assumed value for T_X is correct if Equation (49) is true. If

$$U_D A_D (LMTD)_D < 241\ (T_o - T_X)$$

then T_X has been chosen too low and a larger value must be tried.

7) Next, $T_{2,i}$ is calculated (also be trial and error). A value for $T_{2,i}$ is assumed and Q_W calculated from Equation (52). The hot and cold water temperatures are then calculated from the equations

$$Q_W = R_L (t_h - t_c) = U_W A_W \frac{\left(T_X - t_h - T_i + t_c\right)}{\ln \dfrac{T_X - t_h}{T_i - t_c}} \qquad (53)$$

that is,

$$t_c = t_h - Q_W/R_L \qquad (54)$$

and

$$Q_W = U_W Q_W \frac{\left(T_X - T_i - Q_W/R_L\right)}{\ln \dfrac{T_X - t_h}{T_i - t_h + Q_W/R_L}} \qquad (55)$$

TABLE 2-14. SUMMARY OF WET/DRY COMPRESSOR INTERSTAGE COOLING FOR AIR COMPRESSORS AT FARMINGTON, N.M. WITH WET COOLER OFF FOR MONTHS 1, 2, 3, 11 and 12

Basis: 1000 lb air compressed/hr.

Design intermediate temperature, °F	160
Dry cooler area, ft^2/1000 lb/hr	40.059
Wet cooler area, ft^2/1000 lb/hr	83.853
Circulation rate, gpm/1000 lb/hr	3.046
Average fan & pump energy, kw-hr/1000 lb	0.509
Compression energy, kw-hr/1000 lb	28.140
Water consumed, gal/1000 lb	1.367

TABLE 2-15. ANNUAL AVERAGE COST FOR WET/DRY COMPRESSOR INTERSTAGE COOLING FOR AIR COMPRESSORS AT FARMINGTON, N.M. WITH WET COOLER OFF FOR MONTHS 1, 2, 3, 11 AND 12

Basis: 1000 lb air compressed/hr

Design intermediate temperature, °F	160
Dry cooler cost, ¢/1000 lb	2.140
Wet cooler cost, ¢/1000 lb	2.636
Tower cost, ¢/1000 lb	0.131
Fan and pump energy, ¢/1000 lb	1.018
Compression energy cost, ¢/1000 lb	59.263
Total, ¢/1000 lb compressed	65.188
Water consumed, gal/1000 lb	1.367

so,

$$t_h(e^k-1) = e^k(T_i+Q_W/R_L) - T_X \tag{56}$$

where

$$k = \frac{U_W A_W}{Q_W}(T_X-T_i-Q_W/R_L) \tag{57}$$

If the cold water temperature calculated this way is colder than the value given by the cooling tower curves[6] at the prevailing wet bulb temperature and hot water temperature, then $T_{2,i}$ has been chosen too low and a higher temperature must be tried.

8) Steps 5, 6 and 7 are then repeated for Stage 2. This will result in a hot and cold water temperature different from those calculated in Step 7. However, the cold water to both wet coolers must have the same temperature because it all comes from the same cooling tower basin. The hot water temperature to the tower is the temperature resulting from mixing the two streams. It is necessary, therefore, to determine those hot and cold water temperatures which satisfy the calculations for both stages. In fact the cold water temperatures for the two stages found by the above procedure did not differ very much. For a second iteration an average cold water temperature was taken. This allows calculation without further use of the cooling tower curves. If t_h is eliminated from Equations (54) and (55) one obtains

$$Q_w = U_w A_w \frac{T_x - T_i - Q_w/R_L}{\ln \dfrac{T_x - t_c - Q_w/R_L}{T_i - t_c}} \tag{58}$$

A convenient procedure is to assume T_i, calculate Q_w from Equation (52) and to use the calculated value of Q_w in the right hand side of Equation (58) to redetermine Q_w. A few iterations give the correct value of T_i and Q_w.

The procedure is to return to Step 7 and recalculate $T_{2,i}$ using Equation (58). $T_{2,o}$ is calculated using Equation (48). $T_{x,2}$ is calculated as described in Step 6. $T_{3,i}$ is calculated using Equation (58) again, and calculation proceeds to the exit of the system. The hot circulating water temperature is given by

$$t_h \text{ (average)} = \frac{Q_{w,1} + Q_{w,2} + Q_{w,3} + t_c\left(R_{L,1} + R_{L,2} + R_{L,3}\right)}{R_{L,1} + R_{L,2} + R_{L,3}} \qquad (59)$$

9) For air separation there is little benefit to having $T_{air} < 95°F$ so the third stage water cooler is turned off when $T_{X,3} \leq 95°F$.

10) The calculations of all the temperatures are made month by month beginning with the hottest month and continuing through successively cooler months. In the colder months little benefit is obtained from the wet cooler. The purpose of the wet cooler is to decrease the energy consumed in compression. When $(T_X - T_i) \leq 5°F$, the wet cooler gives less than one percent reduction in compression energy and we turned off the wet coolers, circulating water and tower when $T_X - T_i < 5°F$. This occurred only at Beulah, North Dakota.

11) From the above calculations the grand total wet load each month is known, and so the water evaporated can now be calculated using the procedure previously given.

12) The fan and pump energies are calculated as previously described.

13) The compression energy is calculated from Equation (41).

2.3.4 Best Results

The results for Farmington, New Mexico, Casper, Wyoming and Beulah, North Dakota are shown on Tables 2-16 to 2-18, with summaries on Table 2-19.

TABLE 2-16. CALCULATIONS ON INTERSTAGE COOLING OF AN AIR COMPRESSOR HANDLING 1000 LB AIR/HR AT FARMINGTON, N.M.

Design intermediate temperature T_x = 140°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb	
	$A_{D,1}$ = 29.306	$A_{W,1}$ = 34.914	$R_{L,1}$ = 298.84	$R_{G,1}$ = 0.598	$Q_{W,1}$ = 7471
	$A_{D,2}$ = 16.147	$A_{W,2}$ = 20.948	$R_{L,2}$ = 298.84	$R_{G,2}$ = 0.598	$Q_{W,2}$ = 7471
	$A_{D,3}$ = 13.027	$A_{W,3}$ = 19.506	$R_{L,3}$ = 347.04	$R_{G,3}$ = 0.694	$Q_{W,3}$ = 8676
	Total: 58.480	75.368	944.72	1.890	23,618

Cooling Tower Characteristic
KaY/L = 1.24

Water/Gas Rate in Tower
R_L/R_A = 2.12

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	146.5	155.3	166.4	175.2	189.0	201.4	208.9	205.2	194.0	178.0	162.8	147.8
$T_{x,1}$	62	70	80	87	99	110	116	113	103	90	77	64
$T_{2,i}$	55	62	69	74	83	90	95	93	86	76	67	57
$T_{2,o}$	183	191	200	206	218	226	233	230	221	209	198	185
$T_{x,2}$	69	77	86	92	104	113	119	116	107	95	83	71
$T_{3,i}$	60	66	73	77	86	92	97	95	88	79	71	61
$T_{3,o}$	189	196	205	210	221	229	235	233	224	213	203	190
$T_{x,3}$	71	78	87	94	105	114	120	117	108	96	84	72
T_{air}	71	78	87	94	84	89	94	92	86	77	84	72
t_c (avg)	54	59	65	68	76	81	85	84	78	70	63	55
t_h (avg)	60	68	75	80	90	97	103	100	93	83	72	62
Q_{W1}	1687	1928	2651	3133	3856	4820	5061	4820	4097	3374	2410	1687
Q_{W2}	2169	2651	3133	3615	4338	5061	5302	5061	4579	3856	2892	2410
Q_{W3}	0	0	0	0	5061	6025	6266	6025	5302	4338	0	0
Total Q_W	3856	4579	5784	6748	13255	15906	16629	15906	13978	11568	5302	4097
Total air fan energy (kw-hr/1000 lb)	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655	0.655
Tower fan energy (kw-hr/1000 lb)	0.011	0.011	0.011	0.011	0.017	0.017	0.017	0.017	0.017	0.017	0.011	0.011
Circulation pump energy (kw-hr/1000 lb)	0.029	0.029	0.029	0.029	0.046	0.046	0.046	0.046	0.046	0.046	0.029	0.029
Compression energy (kw-hr/1000 lb)	26.482	26.830	27.231	27.509	28.240	28.414	28.693	28.571	28.171	27.614	27.109	26.552
Water consumed (gal/1000 lb)	0.267	0.337	0.449	0.588	1.177	1.460	1.578	1.493	1.257	0.936	0.396	0.278

(continued)

TABLE 2-16 (continued)

Design intermediate temperature T_x = 160°F; Fraction dry load = 0.638

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb		gpm/1000 lb	
	$A_{D,1}$ = 19.688	$A_{W,1}$ = 39.61	$R_{L,1}$ = 491.64	$R_{G,1}$ = 0.983	$Q_{W,1}$ = 12,291	Cooling Tower Characteristic
	$A_{D,2}$ = 11.26	$A_{W,2}$ = 23.767	$R_{L,2}$ = 491.64	$R_{G,2}$ = 0.983	$Q_{W,2}$ = 12,291	KaY/L = 1.24
	$A_{D,3}$ = 9.111	$A_{W,3}$ = 20.476	$R_{L,3}$ = 539.84	$R_{G,3}$ = 1.080	$Q_{W,3}$ = 13,496	Water/Gas Rate in Tower
	Total: 40.059	83.853	1523.12	3.046	38,078	R_L/R_A = 2.12

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	146.5	155.3	166.4	175.2	189.0	201.4	208.9	205.2	194.0	178.0	162.8	147.8
$T_{X,1}$	80	88	98	106	118	129	136	132	122	108	95	81
$T_{2,i}$	62	68	75	78	87	94	98	96	90	82	73	63
$T_{2,o}$	191	199	208	211	223	231	236	234	226	216	205	193
$T_{X,2}$	93	101	110	115	127	136	141	139	130	118	107	95
$T_{3,i}$	68	75	80	84	91	96	101	99	93	88	78	69
$T_{3,o}$	199	208	214	219	228	234	240	238	230	224	211	200
$T_{X,3}$	97	104	112	118	126	137	143	140	132	122	109	98
T_{air}	67	73	78	82	87	93	98	96	90	85	77	68
t_c (avg)	59	64	72	72	79	84	88	86	81	76	68	60
t_h (avg)	70	75	86	86	96	102	107	105	98	90	80	70
Q_{W1}	4338	4820	5543	6748	7471	8435	9158	8676	7712	6266	5302	4338
Q_{W2}	6025	6266	7230	7471	8676	9640	9833	9640	8917	7230	6989	6266
Q_{W3}	7230	7471	8194	8676	9399	10604	10848	10604	10122	8917	7712	7230
Total Q_W	17593	18557	20967	22895	25546	28679	29839	28920	26751	22413	20003	17834
Total air fan energy (kw-hr/1000 lb)	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449	0.449
Tower fan energy (kw-hr/1000 lb)	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
Circulation pump energy (kw-hr/1000 lb)	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Compression energy (kw-hr/1000 lb)	26.743	27.091	27.457	27.701	28.171	28.554	28.815	28.693	28.327	27.875	27.335	26.795
Water consumed (gal/1000 lb)	1.147	1.302	1.613	1.880	2.242	2.639	2.760	2.674	2.372	1.837	1.475	1.207

(continued)

TABLE 2-16 (continued)

Design intermediate temperature $T_x = 180°F$

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1} = 12.743$	$A_{W,1} = 43.485$	$R_{L,1} = 684.44$	$R_{G,1} = 1.369$	$Q_{W,1} = 17,111$	Cooling Tower Characteristic
	$A_{D,2} = 7.779$	$A_{W,2} = 26.091$	$R_{L,2} = 684.44$	$R_{G,2} = 1.369$	$Q_{W,2} = 17,111$	KaY/L = 1.24
	$A_{D,3} = 6.297$	$A_{W,3} = 21.647$	$R_{L,3} = 732.64$	$R_{G,3} = 1.465$	$Q_{W,3} = 18,316$	Water/Gas Rate in Tower
	Total: 26.819	91.123	2101.52	4.203	52,538	$R_L/R_A = 2.12$

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	146.5	155.3	166.4	175.2	189.0	201.4	208.9	205.2	194.0	178.0	162.8	147.8
$T_{X,1}$	98	106	116	124	137	148	155	152	142	127	113	99
$T_{2,i}$	63	67	78	82	90	96	100	98	92	87	77	63
$T_{2,o}$	193	198	211	216	226	234	239	236	229	223	210	193
$T_{X,2}$	116	122	133	139	149	158	164	161	153	144	131	116
$T_{3,i}$	73	77	84	87	94	98	102	101	96	90	84	73
$T_{3,o}$	205	210	219	223	231	236	241	240	234	226	219	205
$T_{X,3}$	122	128	137	143	152	159	165	163	156	145	136	123
T_{air}	71	75	82	84	91	94	99	97	92	86	82	72
t_c (avg)	59	66	72	74	81	85	88	87	83	73	71	59
t_h (avg)	73	82	87	91	100	105	110	108	101	89	86	73
Q_{W1}	8435	9399	9158	10122	11327	12532	13255	13014	12050	9640	8676	8676
Q_{W2}	10363	10845	11809	12532	13255	14460	14942	14460	13737	13014	11327	10363
Q_{W3}	12291	12773	13255	14219	14701	15665	15906	15906	15424	14219	13014	12291
Total Q_W	31089	33017	34222	36873	39283	42657	44103	43380	41211	36873	33017	31330
Total air fan energy (kw-hr/1000 lb)	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300	0.300
Tower fan energy (kw-hr/1000 lb)	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Circulation pump energy (kw-hr/1000 lb)	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103
Compression energy (kw-hr/1000 lb)	26.847	27.109	27.579	27.823	28.275	28.623	28.867	28.763	28.414	27.997	27.509	26.865
Water consumed (gal/1000 lb)	2.106	2.416	2.654	3.070	3.463	3.891	4.165	4.046	3.665	3.035	2.511	2.142

(continued)

TABLE 2-16 (continued)

Design intermediate temperature T_x = all wet

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb	
	$A_{D,1} = 0$	$A_{W,1} = 51.365$	$R_{L,1} = 1224.28$	$R_{G,1} = 2.449$	$Q_{W,1} = 30,607$
	$A_{D,2} = 0$	$A_{W,2} = 30.820$	$R_{L,2} = 1224.28$	$R_{G,2} = 2.449$	$Q_{W,2} = 30,607$
	$A_{D,3} = \underline{0}$	$A_{W,3} = \underline{24.375}$	$R_{L,3} = \underline{1272.48}$	$R_{G,3} = \underline{2.545}$	$Q_{W,3} = \underline{31,812}$
	Total: 0	106.560	3721.04	7.443	93,026

Cooling Tower Characteristic
KaY/L = 1.24

Water/Gas Rate in Tower
$R_L/R_A = 2.12$

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	146.5	155.3	166.4	175.2	189.0	201.4	208.9	205.2	194.0	178.0	162.8	147.8
$T_{X,1}$	147	155	166	175	189	201	209	205	194	178	163	148
$T_{2,i}$	72	77	83	86	93	97	102	100	95	90	81	73
$T_{2,o}$	204	210	218	221	230	235	241	239	233	226	215	205
$T_{X,2}$	204	210	218	221	230	235	241	239	233	226	215	205
$T_{3,i}$	84	89	95	98	102	104	108	107	103	101	94	85
$T_{3,o}$	219	225	233	236	241	244	249	248	243	240	231	220
$T_{X,3}$	219	225	233	236	241	244	249	248	243	240	231	220
T_{air}	82	87	93	95	99	101	103	103	100	98	92	83
t_c (avg)	66	71	77	79	84	86	90	89	85	83	75	67
t_h (avg)	85	91	97	100	106	109	114	113	108	103	95	86
Q_{W1}	18075	18798	20003	21449	23136	25064	25787	25305	23859	21208	19762	18075
Q_{W2}	28920	29161	29643	29643	30848	31571	32053	31812	31330	30125	29161	28920
Q_{W3}	33017	33258	33740	33981	34222	34463	35186	34945	34463	34222	33499	33017
Total Q_W	80012	81217	83386	85073	88206	91098	93026	92062	89652	85555	82422	80012
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066	0.066
Circulation pump energy (kw-hr/1000 lb)	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183	0.183
Compression energy (kw-hr/1000 lb)	27.196	27.492	27.857	28.084	28.467	28.745	29.006	28.902	28.589	28.240	27.753	27.248
Water consumed (gal/1000 lb)	5.837	6.216	6.616	7.101	7.796	8.323	8.639	8.471	7.902	7.206	6.532	5.942

TABLE 2-17. CALCULATIONS ON INTERSTAGE COOLING OF AN AIR COMPRESSOR HANDLING 1000 LBS AIR/HR AT CASPER, WYOMING

Design intermediate temperature T_x = 140°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 28.156	$A_{W,1}$ = 34.914	$R_{L,1}$ = 298.84	$R_{G,1}$ = 0.598	$Q_{W,1}$ = 7471	Cooling Tower Characteristic
	$A_{D,2}$ = 14.334	$A_{W,2}$ = 20.948	$R_{L,2}$ = 298.84	$R_{G,2}$ = 0.598	$Q_{W,2}$ = 7471	KaY/L = 1.17
	$A_{D,3}$ = 11.572	$A_{W,3}$ = 19.506	$R_{L,3}$ = 347.04	$R_{G,3}$ = 0.694	$Q_{W,3}$ = 8676	Water/Gas Rate in Tower
	Total: 54.052	75.368	944.72	1.890	23,618	R_L/R_A = 2.24

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	144.0	146.5	154.0	165.2	181.5	195.2	202.7	201.4	187.7	172.7	154.0	151.5
$T_{X,1}$	62	64	71	80	95	106	113	112	100	87	71	69
$T_{2,i}$	55	57	64	70	81	89	93	92	83	75	64	61
$T_{2,o}$	183	185	194	201	215	225	230	229	218	208	194	190
$T_{X,2}$	75	77	84	92	105	116	122	121	110	98	84	81
$T_{3,i}$	62	64	70	77	87	95	99	98	89	82	70	68
$T_{3,o}$	191	194	201	210	223	233	238	237	225	216	201	199
$T_{X,3}$	77	80	86	95	108	119	124	123	112	101	86	84
T_{air}	77	80	86	76	85	93	96	95	87	81	86	84
t_c (avg)	54	56	60	67	76	82	85	84	76	70	60	59
t_h (avg)	61	63	68	77	89	98	102	101	92	83	68	68
Q_{W1}	1687	1687	1687	2410	3374	4097	4820	4820	4097	2892	1687	1928
Q_{W2}	3133	3133	3374	3615	4338	5061	5543	5543	5061	3856	3374	3133
Q_{W3}	0	0	0	4579	5543	6266	6748	6748	6025	4820	0	0
Total Q_W	4820	4820	5061	10604	13255	15424	17111	17111	15183	11568	5061	5061
Total air fan energy (kw-hr/1000 lb)	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605	0.605
Tower fan energy (kw-hr/1000 lb)	0.011	0.011	0.011	0.017	0.017	0.017	0.017	0.017	0.017	0.017	0.011	0.011
Circulation pump energy (kw-hr/1000 lb)	0.029	0.029	0.029	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.029	0.029
Compression energy (kw-hr/1000 lb)	26.482	26.586	26.917	27.300	27.892	28.362	28.606	28.554	28.049	27.579	26.917	26.795
Water consumed (gal/1000 lb)	0.304	0.314	0.354	0.810	1.134	1.392	1.580	1.570	1.327	0.927	0.354	0.349

(continued)

TABLE 2-17 (continued)

Design intermediate temperature T_x = 160°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 18.890	$A_{W,1}$ = 39.612	$R_{L,1}$ = 491.64	$R_{G,1}$ = 0.983	$Q_{W,1}$ = 12,291	Cooling Tower Characteristic
	$A_{D,2}$ = 11.037	$A_{W,2}$ = 23.767	$R_{L,2}$ = 491.64	$R_{G,2}$ = 0.983	$Q_{W,2}$ = 12,291	KaY/L = 1.17
	$A_{D,3}$ = 9.396	$A_{W,3}$ = 20.476	$R_{L,3}$ = 539.84	$R_{G,3}$ = 1.080	$Q_{W,3}$ = 13,496	Water/Gas Rate in Tower
	Total: 39.323	83.855	1523.12	3.046	38,078	R_L/R_A = 2.24

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	144.0	146.5	154.0	165.2	181.5	195.2	202.7	201.4	187.7	172.7	154.0	151.5
$T_{X,1}$	80	82	89	99	113	125	132	131	119	105	89	86
$T_{2,i}$	61	63	69	76	85	93	96	95	86	80	69	66
$T_{2,o}$	190	193	200	209	220	230	234	233	221	214	200	196
$T_{X,2}$	93	95	102	111	123	134	139	138	126	116	102	99
$T_{3,i}$	67	69	75	82	89	96	100	99	89	85	75	72
$T_{3,o}$	198	200	208	216	225	234	239	238	225	220	208	204
$T_{X,3}$	93	95	102	110	122	130	138	137	125	116	102	99
T_{air}	64	66	72	79	86	91	96	95	86	82	72	69
t_c (avg)	57	59	65	71	77	84	86	86	77	74	65	62
t_h (avg)	68	70	76	84	93	101	105	104	93	88	76	74
Q_{W1}	4579	4579	4820	5543	6748	7712	8676	8676	7953	6025	4820	4820
Q_{W2}	6266	6266	6507	6989	8194	9158	9399	9399	8917	7471	6507	6507
Q_{W3}	6989	6989	7230	7471	8676	9399	10122	10122	9399	8194	7230	7230
Total Q_W	17834	17834	18557	20003	23618	26269	28197	28197	26269	21690	18557	18557
Total air fan energy (kw-hr/1000 lb)	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440	0.440
Tower fan energy (kw-hr/1000 lb)	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
Circulation pump energy (kw-hr/1000 lb)	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Compression energy (kw-hr/1000 lb)	26.67	26.78	27.09	27.49	28.00	28.45	28.68	28.62	28.10	27.72	27.09	26.95
Water consumed (gal/1000 lb)	1.151	1.216	1.314	1.535	2.000	2.343	2.571	2.563	2.367	1.755	1.314	1.224

(continued)

TABLE 2-17 (continued)

Design intermediate temperature T_x = 180°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb	
	$A_{D,1}$ = 12.254	$A_{W,1}$ = 43.485	$R_{L,1}$ = 684.44	$R_{G,1}$ = 1.369	$Q_{W,1}$ = 17,111
	$A_{D,2}$ = 6.255	$A_{W,2}$ = 26.091	$R_{L,2}$ = 684.44	$R_{G,2}$ = 1.369	$Q_{W,2}$ = 17,111
	$A_{D,3}$ = 5.068	$A_{W,3}$ = 21.647	$R_{L,3}$ = 732.64	$R_{G,3}$ = 1.465	$Q_{W,3}$ = 18,316
	Total: 23.577	91.123	2101.52	4.203	52,538

Cooling Tower Characteristic
KaY/L = 1.17

Water/Gas Rate in Tower
R_L/R_A = 2.24

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	144.0	146.5	154.0	165.2	181.5	195.2	202.7	201.4	187.7	172.7	154.0	151.5
$T_{X,1}$	97	100	106	116	132	144	151	150	137	124	106	104
$T_{2,i}$	65	67	77	80	88	95	98	97	90	84	77	71
$T_{2,o}$	195	198	210	214	224	233	236	235	226	219	210	203
$T_{X,2}$	128	131	140	146	158	167	171	170	161	146	140	135
$T_{3,i}$	75	76	85	91	97	102	104	103	97	92	85	80
$T_{3,o}$	208	209	220	228	235	241	244	243	235	229	220	214
$T_{X,3}$	136	137	146	155	164	172	176	175	166	158	146	142
T_{air}	73	74	83	90	94	99	101	100	94	91	83	78
t_c (avg)	61	62	68	75	81	86	88	87	81	78	68	66
t_h (avg)	76	78	83	92	100	106	109	108	101	95	83	82
Q_{W1}	7712	7953	6989	8676	10604	11809	12773	12773	11327	9640	6989	7953
Q_{W2}	12773	13255	13255	13255	14701	15665	16147	16147	15424	13014	13255	13255
Q_{W3}	15183	15183	15183	15665	16870	17593	18075	18075	17352	16147	15183	15424
Total Q_W	35668	36391	35427	37596	42175	45067	46995	46995	44103	38801	35427	36632
Total air fan energy (kw-hr/1000 lb)	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264	0.264
Tower fan energy (kw-hr/1000 lb)	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037
Circulation pump energy (kw-hr/1000 lb)	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103
Compression energy (kw-hr/1000 lb)	26.882	26.969	27.405	27.718	28.188	28.589	28.780	28.728	28.310	27.910	27.405	27.178
Water consumed (gal/1000 lb)	2.489	2.590	2.658	2.951	3.593	4.010	4.336	4.302	3.829	3.176	2.658	2.703

(continued)

TABLE 2-17 (continued)

Design intermediate temperature T_x = all wet

Design ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
$A_{D,1} = 0$	$A_{W,1} = 51.134$	$R_{L,1} = 1205.0$	$R_{G,1} = 2.410$	$Q_{W,1} = 30,125$	Cooling Tower Characteristic
$A_{D,2} = 0$	$A_{W,2} = 30.681$	$R_{L,2} = 1205.0$	$R_{G,2} = 2.410$	$Q_{W,2} = 30,125$	KaY/L = 1.17
$A_{D,3} = 0$	$A_{W,3} = 24.292$	$R_{L,3} = 1253.2$	$R_{G,3} = 2.506$	$Q_{W,3} = 31,330$	Water/Gas Rate in Tower
Total: 0	106.107	3663.2	7.326	91,580	$R_L/R_A = 2.24$

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	144.0	146.5	154.0	165.2	181.5	195.2	202.7	201.4	187.7	172.7	154.0	151.5
$T_{X,1}$	144	147	154	165	182	195	203	201	188	173	154	152
$T_{2,i}$	69	73	78	86	91	98	100	99	95	88	78	76
$T_{2,o}$	200	205	211	221	228	236	239	238	233	224	211	209
$T_{X,2}$	200	205	211	221	228	236	239	238	233	224	211	209
$T_{3,i}$	78	83	89	98	102	106	108	107	106	99	89	85
$T_{3,o}$	211	218	225	236	241	246	249	248	246	238	225	220
$T_{X,3}$	211	218	225	236	241	246	249	248	246	238	225	220
T_{air}	77	82	88	96	100	102	104	103	102	97	88	84
t_c (avg)	61	66	72	79	83	88	90	89	87	81	72	69
t_h (avg)	81	86	91	100	105	111	113	112	109	102	91	88
Q_{W1}	18075	17834	18316	19039	21931	23377	24823	24582	22413	20485	18316	18316
Q_{W2}	29402	29402	29402	29643	30366	31330	31571	31571	30607	30125	29402	29884
Q_{W3}	32294	32776	33017	33740	33981	34704	34945	34945	34704	33981	33017	32776
Total Q_W	79771	80012	80735	82422	86278	89411	91339	91098	87724	84591	80735	80976
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Circulation pump energy (kw-hr/1000 lb)	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180
Compression energy (kw-hr/1000 lb)	27.004	27.196	27.492	27.944	28.327	28.710	28.885	28.832	28.554	28.101	27.492	27.352
Water consumed (gal/1000 lb)	5.890	5.949	6.223	6.577	7.362	7.951	8.285	8.245	7.657	7.028	6.223	6.184

TABLE 2-18 CALCULATIONS ON INTERSTAGE COOLING OF AN AIR COMPRESSOR HANDLING 1000 LBS AIR/HR AT BEULAH, NORTH DAKOTA

Design intermediate temperature $T_x = 140°F$

Design	ft^2/1000 lb		ft^2/1000 lb		lb/1000 lb		gpm/1000 lb		
$A_{D,1}$ =	31.92	$A_{W,1}$ =	34.91	$R_{L,1}$ =	298.8	$R_{G,1}$ =	0.598	$Q_{W,1}$ =	7,471
$A_{D,2}$ =	20.19	$A_{W,2}$ =	20.95	$R_{L,2}$ =	298.8	$R_{G,2}$ =	0.598	$Q_{W,2}$ =	7,471
$A_{D,3}$ =	13.16	$A_{W,3}$ =	19.46	$R_{L,3}$ =	347.0	$R_{G,3}$ =	0.694	$Q_{W,3}$ =	8,676
Total:	65.27		75.32		944.6		1.890		23,618

Cooling Tower Characteristic
KaY/L = 1.30

Water/Gas Rate in Tower
$R_L/R_A = 1.85$

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	124.0	132.7	144.0	167.7	183.9	195.1	203.9	201.4	186.4	171.4	148.9	136.5
$T_{X,1}$	33	40	50	70	83	93	100	98	85	73	54	44
$T_{2,i}$	33	40	50	64	74	82	83	85	78	67	54	44
$T_{2,o}$	155	164	176	194	206	216	218	220	211	198	181	169
$T_{X,2}$	49	56	66	84	97	107	112	111	101	88	70	60
$T_{3,i}$	49	56	66	69	79	87	88	90	84	73	70	60
$T_{3,o}$	175	184	196	200	213	223	224	226	219	205	201	189
$T_{X,3}$	54	62	71	86	99	108	114	113	102	90	76	65
T_{air}	54	62	71	86	78	86	86	88	83	90	76	65
t_c (avg)	-	-	-	61	70	77	75	79	75	65	-	-
t_h (avg)	-	-	-	76	82	91	93	94	86	79	-	-
Q_{W1}	0	0	0	1470	2090	2580	4050	3070	1600	1250	0	0
Q_{W2}	0	0	0	3770	4400	4890	6070	5240	4260	3770	0	0
Q_{W3}	0	0	0	0	5180	5580	6990	6040	4880	0	0	0
Total Q_W	0	0	0	5240	11670	13050	17110	14350	10740	5020	0	0
Total air fan energy (kw-hr/1000 lb)	0.731	0.731	0.731	0.731	0.731	0.731	0.731	0.731	0.731	0.731	0.731	0.731
Tower fan energy (kw-hr/1000 lb)	0	0	0	0.011	0.017	0.017	0.017	0.017	0.017	0.011	0	0
Circulation pump energy (kw-hr/1000 lb)	0	0	0	0.029	0.046	0.046	0.046	0.046	0.046	0.029	0	0
Compression energy (kw-hr/1000 lb)	25.562	25.928	26.432	27.059	27.633	28.068	28.225	28.259	27.824	27.233	26.641	26.119
Water consumed (gal/1000 lb)	0	0	0	0.423	0.992	1.226	1.624	1.367	0.974	0.407	0	0

(continued)

TABLE 2-18 (Continued)

Design intermediate temperature T_x = 160°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb		gpm/1000 lb	
	$A_{D,1}$ = 21.56	$A_{W,1}$ = 39.61	$R_{L,1}$ = 491.6	$R_{G,1}$ = 0.983	$Q_{W,1}$ = 12,291	Cooling Tower Characteristic KaY/L = 1.30
	$A_{D,2}$ = 13.64	$A_{W,2}$ = 23.76	$R_{L,2}$ = 491.6	$R_{G,2}$ = 0.983	$Q_{W,2}$ = 12,291	Water/Gas Rate in Tower
	$A_{D,3}$ = 8.90	$A_{W,3}$ = 20.88	$R_{L,3}$ = 539.8	$R_{G,3}$ = 1.080	$Q_{W,3}$ = 13,496	R_L/R_A = 1.85
	Total: 44.10	84.25	1523.0	3.046	38,078	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	124.0	132.7	144.0	167.7	183.9	195.1	203.9	201.4	186.4	171.4	148.9	136.5
$T_{X,1}$	49	57	67	87	101	111	119	117	104	90	71	60
$T_{2,i}$	49	57	67	72	79	88	94	92	84	73	66	60
$T_{2,o}$	175	185	198	204	213	224	231	229	219	205	196	189
$T_{X,2}$	78	86	97	110	121	131	138	136	125	112	98	89
$T_{3,i}$	56	60	68	78	84	92	98	97	89	78	73	70
$T_{3,o}$	184	189	199	211	219	229	236	235	225	211	205	201
$T_{X,3}$	82	88	97	113	124	133	140	139	128	115	102	94
T_{air}	82	88	67	77	81	91	96	96	88	77	72	94
t_c (avg)	50	52	60	68	73	81	86	85	78	68	65	64
t_h (avg)	61	65	74	81	89	97	103	102	93	82	77	74
Q_{W1}	0	0	0	3510	5180	5600	6190	5930	4850	4070	1080	0
Q_{W2}	5180	6360	6850	7860	8950	9280	9700	9530	8780	8190	6190	4680
Q_{W3}	0	0	7180	8790	9680	10110	10450	10580	9770	9130	7180	0
Total Q_W	5180	6360	14030	20160	23810	24990	26340	26040	21390	23400	14450	4680
Total air fan energy (kw-hr/1000 lb)	0.494	0.494	0.494	0.494	0.494	0.494	0.494	0.494	0.494	0.494	0.494	0.494
Tower fan energy (kw-hr/1000 lb)	0.009	0.009	0.018	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.009
Circulation pump energy (kw-hr/1000 lb)	0.024	0.024	0.051	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.024
Compression energy (kw-hr/1000 lb)	25.963	26.293	26.763	27.355	27.807	28.259	28.590	28.503	28.016	27.424	26.902	26.572
Water consumed (gal/1000 lb)	0.263	0.375	0.920	1.578	1.922	2.332	2.519	2.461	2.036	1.720	0.978	0.263

(continued)

TABLE 2-18 (Continued)

Design intermediate temperature $T_x = 180°F$

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1} = 14.28$	$A_{W,1} = 43.48$	$R_{L,1} = 684.4$	$R_{G,1} = 1.369$	$Q_{W,1} = 17,111$	Cooling Tower Characteristic KaY/L = 1.30
	$A_{D,2} = 9.05$	$A_{W,2} = 26.09$	$R_{L,2} = 684.4$	$R_{G,2} = 1.369$	$Q_{W,2} = 17,111$	Water/Gas Rate in Tower $R_L/R_A = 1.85$
	$A_{D,3} = 5.91$	$A_{W,3} = 22.34$	$R_{L,3} = 732.6$	$R_{G,3} = 1.465$	$Q_{W,3} = 18,316$	
	Total: 29.24	91.91	2101.4	4.203	52,538	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	124.0	132.7	144.0	167.7	183.9	195.1	203.9	201.4	186.4	171.4	148.9	136.5
$T_{X,1}$	66	74	84	106	120	131	138	136	123	109	89	78
$T_{2,i}$	49	54	63	75	84	90	96	94	87	78	68	60
$T_{2,o}$	175	181	193	207	219	226	234	231	223	211	199	189
$T_{X,2}$	101	108	119	135	147	155	163	160	150	138	124	114
$T_{3,i}$	55	60	70	81	89	94	101	98	91	83	75	66
$T_{3,o}$	183	189	201	215	225	231	240	236	228	218	208	196
$T_{X,3}$	81	88	98	106	127	134	142	139	129	118	103	92
T_{air}	81	88	65	75	84	89	96	93	87	78	70	92
t_c (avg)	45	50	59	69	76	81	87	85	79	71	64	56
t_h (avg)	56	62	71	82	92	98	104	102	95	87	76	68
Q_{W1}	4220	4750	4930	7300	8800	9980	10160	10160	8800	7610	4930	4390
Q_{W2}	11170	11520	12010	13190	14210	14740	15220	14910	14080	13370	12010	11520
Q_{W3}	0	0	7980	7620	10460	10820	11330	11000	10280	9580	7980	0
Total Q_W	15390	16270	24920	28110	33470	35540	36710	36070	33160	30560	24920	15910
Total air fan energy (kw-hr/1000 lb)	0.327	0.327	0.327	0.327	0.327	0.327	0.327	0.327	0.375	0.327	0.327	0.327
Tower fan energy (kw-hr/1000 lb)	0.024	0.024	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.024
Circulation pump energy (kw-hr/1000 lb)	0.067	0.067	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.067
Compression energy (kw-hr/1000 lb)	25.945	26.241	26.728	27.459	27.981	28.329	28.677	28.555	28.103	27.598	26.972	26.502
Water consumed (gal/1000 lb)	0.790	0.950	1.624	2.223	2.836	3.341	3.491	3.409	2.891	2.468	1.677	0.950

(continued)

TABLE 2-18 (Concluded)

Design intermediate temperature T_x = all wet

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb		gpm/1000 lb
	$A_{D,1}$ = 0	$A_{W,1}$ = 51.96	$R_{L,1}$ = 1275.4	$R_{G,1}$ = 2.551	$Q_{W,1}$ = 31,884
	$A_{D,2}$ = 0	$A_{W,2}$ = 31.74	$R_{L,2}$ = 1359.2	$R_{G,2}$ = 2.718	$Q_{W,2}$ = 33,981
	$A_{D,3}$ = 0	$A_{W,3}$ = 26.29	$R_{L,3}$ = 1407.4	$R_{G,3}$ = 2.815	$Q_{W,3}$ = 35,186
	Total: 0	110.00	4042.0	8.084	101,051

Cooling Tower Characteristic
KaY/L = 1.30

Water/Gas Rate in Tower
R_L/R_A = 1.85

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	124.0	132.7	144.0	167.7	183.9	195.1	203.9	201.4	186.4	171.4	148.9	136.5
$T_{X,1}$	124	133	144	168	184	195	204	201	187	171	149	137
$T_{2,i}$	59	62	70	82	90	96	99	99	92	87	76	68
$T_{2,o}$	188	191	201	216	226	234	238	238	229	223	209	199
$T_{X,2}$	188	191	201	216	226	234	238	238	229	223	209	199
$T_{3,i}$	65	67	75	87	94	100	102	102	97	92	82	75
$T_{3,o}$	195	198	208	223	231	239	241	241	235	229	216	208
$T_{X,3}$	195	198	208	223	231	239	241	241	235	229	216	208
T_{air}	65	67	75	86	93	99	101	101	96	92	81	74
t_c (avg)	52	54	62	73	80	85	88	87	82	78	68	61
t_h (avg)	71	73	82	94	102	107	111	110	104	99	88	81
Q_{W1}	15500	17090	17660	20390	22360	23760	24900	25350	22500	20010	17470	16260
Q_{W2}	29600	29800	30180	31220	31800	32630	32560	33020	32250	31600	30830	30250
Q_{W3}	31550	31750	32130	32910	33100	33980	33490	33980	33780	33400	32520	32330
Total Q_W	76650	78640	79970	84520	87260	90370	90950	92350	88530	85010	80820	78840
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078	0.078
Circulation pump energy (kw-hr/1000 lb)	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217	0.217
Compression energy (kw-hr/1000 lb)	26293	26502	26937	27685	28172	28538	28747	28712	28294	27911	27233	26798
Water consumed (gal/1000 lb)	4.538	5.110	5.508	6.688	7.344	8.210	8.542	8.656	7.738	6.898	5.770	5.246

TABLE 2-19 SUMMARY OF WET/DRY COMPRESSOR INTERSTAGE COOLING FOR AIR COMPRESSOR

Farmington, New Mexico

Basis: 1000 lb air compressed/hr.

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler area, ft^2/1000 lb/hr	58.480	40.059	26.819	0
Wet cooler area, ft^2/1000 lb/hr	75.368	83.853	91.123	106.560
Circulation rate, gpm/1000 lb/hr	1.890	3.046	4.203	7.443
Avg. fan & pump energy, kw-hr/1000 lb	0.704	0.551	0.440	0.249
Compression energy, kw-hr/1000 lb	27.618	27.796	27.889	28.132
Water consumed, gal/1000 lb	0.851	1.929	3.097	7.215

Casper, Wyoming

Basis: 1000 lb/air compressed/hr.

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler area, ft^2/1000 lb	54.052	39.323	23.577	0
Wet cooler area, ft^2/1000 lb	75.368	83.855	91.123	106.107
Circulation rate, gpm/1000 lb/hr	1.890	3.046	4.203	7.326
Avg. fan & pump energy, kw-hr/1000 lb	0.658	0.542	0.404	0.245
Compression energy, kw-hr/1000 lb	27.503	27.640	27.839	27.991
Water consumed, gal/1000 lb	0.868	1.779	3.275	6.965

Beulah, North Dakota

Basis: 1000 lb air compressed/hr.

Design intermediate temperature, °F	140	160	180	all wet
Dry cooler area, ft^2/1000 lb/hr	65.27	44.10	29.24	0
Wet cooler area, ft^2/1000 lb/hr	75.32	84.75	91.91	110.0
Circulation rate, gpm/1000 lb/hr	1.890	3.046	4.203	8.084
Avg. fan & pump energy, kw-hr/1000 lb	0.764	0.576	0.455	0.295
Compression energy, kw-hr/1000 lb	27.082	27.371	27.424	27.652
Water consumed, gal/1000 lb	0.584	1.447	2.221	6.686

2.4 HYDROGEN COMPRESSORS IN COAL CONVERSION PLANTS

Hydrogen compressors are important in direct hydrogenation plants, mostly coal liquification and solvent refined coal plants. The energy consumed in compressing a gas is inversely proportional to the molecular weight and hydrogen compressors will not be the same as air compressors.

The example chosen for study is shown on Figure 2-24. Hydrogen is assumed to be produced at 400 psia and 95°F leaving the gas purification system. A three stage compressor, having a compression ratio of 2.15 per stage, is used to compress the hydrogen to 4000 psi. The compressed hydrogen is used hot so coolers do not follow stage three.

For hydrogen the following values apply:

w = 16.67 lb/min = 1000 lb/hr
e = 0.77, polytropic efficiency
$Z_s Z_d$ = 1.0, compressibility at suction and discharge
k = 1.41, ratio of specific heats
M_w = 2, molecular weight $(n-1)/n = 0.378$
c_p = 3.47 btu/(lb)(°F)

Calculations proceed as for the air compressor already described, with changes for the change in gas. Stage outlet temperatures are calculated from stage inlet temperatures by Equation (40) which becomes

$$T_o = 1.336\ T_i \tag{60}$$

replacing Equation (48). It must not be forgotten that the temperatures in Equation (60) are in °R (= 460 + °F). The compression power per stage is

$$\begin{aligned} P &= 1.0\ Ti\ (r^{0.378} - 1) \\ &= 0.336\ T_i \end{aligned} \tag{61}$$

which replaces Equation (44). The load on a cooler is

$$Q = 3460\ (T_{in} - T_{out}) \tag{62}$$

which replaces Equation (47).

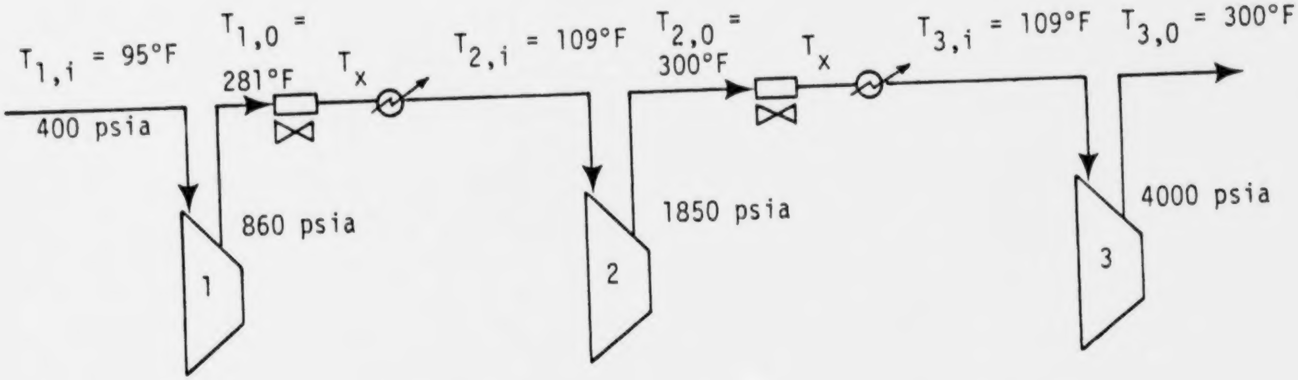
$T_{1,i}$ = 95°F
400 psia
$T_{1,0}$ = 281°F
T_x
860 psia
1
$T_{2,i}$ = 109°F
$T_{2,0}$ = 300°F
T_x
1850 psia
2
$T_{3,i}$ = 109°F
$T_{3,0}$ = 300°F
4000 psia
3

Figure 2-24. Hydrogen compressor design conditions.

1) The stage outlet temperatures are calculated from Equation (60).

2) The dry cooler areas are calculated as described in Step 2 for air compressors.

3) The wet cooler areas are calculated as described in Step 3 for air compressors.

4) The circulating water flow rates are calculated as described in Step 4 for air compressors.

5) Since the entry to Stage 1 is constant at 95°F, the exit is constant at 281°F.

6) The exit from the first dry cooler, $T_{X,1}$, is calculated as described in Step 6 for air compressors.

7) A first calculation of $T_{2,i}$ and of the cold temperature of the circulating water, t_c, is made as described in Step 7 for air compressors.

8) Stage 2 is calculated by repeating Steps 6 and 7. An average cold water temperature is determined and the second calculations made as described under Step 8 for air compressors.

9) The remaining calculations are made as for air compressors.

The results for Farmington, New Mexico, Casper, Wyoming and Beulah, North Dakota are shown on Table 2-20 to 2-22 with summaries on Table 2-23.

TABLE 2-20 CALCULATIONS ON INTERSTAGE COOLING OF A HYDROGEN COMPRESSOR HANDLING 1000 LB H_2/HR AT FARMINGTON, NEW MEXICO

Design intermediate temperature T_x = 115°F (all dry)

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 105.648	$A_{W,1}$ = 0	$R_{L,1}$ = 0	$R_{G,1}$ = 0	$Q_{W,1}$ = 0	Cooling Tower Characteristic KaY/L = 1.24
	$A_{D,2}$ = 112.096	$A_{W,2}$ = 0	$R_{L,2}$ = 0	$R_{G,2}$ = 0	$Q_{W,2}$ = 0	Water/Gas Rate in Tower R_L/R_A = 2.12
	Total: 217.744	0	0	0	0	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	50	56	64	71	81	90	95	93	84	72	62	51
$T_{2,i}$	50	56	64	71	81	90	95	93	84	72	62	51
$T_{2,o}$	221	229	240	249	263	275	281	279	267	251	237	223
$T_{X,2}$	42	49	58	65	76	87	93	90	80	67	55	43
$T_{3,i}$	42	49	58	65	76	87	93	90	80	67	55	43
$T_{3,o}$	211	220	232	241	256	271	279	275	261	244	228	212
t_c (avg)	-	-	-	-	-	-	-	-	-	-	-	-
t_h (avg)	-	-	-	-	-	-	-	-	-	-	-	-
Q_{W1}	0	0	0	0	0	0	0	0	0	0	0	0
Q_{W2}	0	0	0	0	0	0	0	0	0	0	0	0
Total Q_W	0	0	0	0	0	0	0	0	0	0	0	0
Total air fan energy (kw-hr/1000 lb)	2.831	2.831	2.831	2.831	2.831	2.831	2.831	2.831	2.831	2.831	2.831	2.831
Tower fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Circulation pump energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Compression energy (kw-hr/1000 lb)	514.476	518.744	524.326	528.922	535.817	542.383	545.995	544.353	538.115	529.907	522.684	515.133
Water consumed (gal/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0

(continued)

TABLE 2-20 (Farmington, N.M.) (Continued)

Design intermediate temperature $T_x = 140°F$

Design	$ft^2/1000\ lb$	$ft^2/1000\ lb$	$lb/1000\ lb$	$gpm/1000\ lb$		
	$A_{D,1} = 65.636$	$A_{W,1} = 40.100$	$R_{L,1} = 4290.4$	$R_{G,1} = 8.5808$	$Q_{W,1} = 107,260$	Cooling Tower Characteristic $KaY/L = 1.24$
	$A_{D,2} = 70.394$	$A_{W,2} = 40.100$	$R_{L,2} = 4290.4$	$R_{G,2} = 8.5808$	$Q_{W,2} = 107,260$	Water/Gas Rate in Tower $R_L/R_A = 2.12$
	Total: 136.030	80.200	8580.8	17.1616	214,520	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	85	90	97	103	111	119	124	121	114	104	95	86
$T_{2,i}$	69	74	79	83	90	96	100	98	92	86	78	70
$T_{2,o}$	247	253	260	265	275	283	288	285	277	269	259	248
$T_{X,2}$	72	79	87	94	105	114	120	117	108	96	85	73
$T_{3,i}$	61	67	73	79	87	93	97	95	89	81	72	63
$T_{3,o}$	236	244	252	260	271	279	284	281	273	263	251	239
t_c (avg)	58	64	68	72	79	84	87	85	80	75	68	60
t_h (avg)	69	75	81	86	95	102	106	103	97	89	80	71
Q_{W1}	55360	55360	62280	69200	72660	79580	83040	79580	76120	62280	58820	55360
Q_{W2}	38060	41520	48440	51900	62280	72660	79580	76120	65740	51900	44980	34600
Total Q_W	93420	96880	110720	121100	134940	152240	162620	155700	141860	114180	103800	89960
Total air fan energy (kw-hr/1000 lb)	1.768	1.768	1.768	1.768	1.768	1.768	1.768	1.768	1.768	1.768	1.768	1.768
Tower fan energy (kw-hr/1000 lb)	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153
Circulation pump energy (kw-hr/1000 lb)	0.422	0.422	0.422	0.422	0.422	0.422	0.422	0.422	0.422	0.422	0.422	0.422
Compression energy (kw-hr/1000 lb)	526.952	530.564	534.175	537.456	542.383	546.323	548.950	547.636	543.697	539.100	533.519	527.937
Water consumed (gal/1000 lb)	6.171	6.851	8.357	10.058	12.002	14.140	15.306	14.480	12.682	9.329	7.726	5.928

(continued)

TABLE 2-20 (Farmington, N.M.) (Continued)

Design intermediate temperature T_x = 160°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 49.049	$A_{W,1}$ = 45.496	$R_{L,1}$ = 7058.4	$R_{G,1}$ = 14.117	$Q_{W,1}$ = 176,460	Cooling Tower Characteristic KaY/L = 1.24
	$A_{D,2}$ = 53.462	$A_{W,2}$ = 45.496	$R_{L,2}$ = 7058.4	$R_{G,2}$ = 14.117	$Q_{W,2}$ = 176,460	Water/Gas Rate in Tower R_L/R_A = 2.12
	Total: 102.511	90.992	14116.8	28.234	352,920	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{x,1}$	112	116	123	128	135	142	146	144	138	129	121	113
$T_{2,i}$	76	80	87	89	95	99	103	101	96	92	85	77
$T_{2,o}$	256	261	271	273	281	287	292	289	283	277	268	257
$T_{x,2}$	96	103	112	118	128	137	142	139	131	120	109	98
$T_{3,i}$	69	75	81	84	92	97	101	99	93	87	80	70
$T_{3,o}$	247	255	263	267	277	284	289	287	279	271	261	248
t_c (avg)	63	68	74	76	82	86	89	88	83	79	73	64
t_h (avg)	79	84	90	94	101	106	110	108	102	96	89	80
Q_{W1}	124560	124560	124560	134940	138400	148780	148780	148780	145320	128020	124560	124560
Q_{W2}	93420	96880	107260	117640	124560	138400	141860	138400	131480	114180	100340	96880
Total Q_W	217980	221440	231820	252580	262960	287180	290640	287180	276800	242200	224900	221440
Total air fan energy (kw-hr/1000 lb)	1.333	1.333	1.333	1.333	1.333	1.333	1.333	1.333	1.333	1.333	1.333	1.333
Tower fan energy (kw-hr/1000 lb)	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251
Circulation pump energy (kw-hr/1000 lb)	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695
Compression energy (kw-hr/1000 lb)	543.436	546.790	551.151	552.829	557.525	560.544	563.228	561.886	558.196	554.841	550.145	544.107
Water consumed (gal/1000 lb)	15.028	16.148	18.306	20.944	23.182	26.300	27.579	26.380	24.781	20.065	17.187	15.348

(continued)

TABLE 2-20 (Farmington, N.M.) (Continued)

Design intermediate temperature T_x = 180°F

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb	
	$A_{D,1}$ = 36.860	$A_{W,1}$ = 49.945	$R_{L,1}$ = 4290.4	$R_{G,1}$ = 17.162	$Q_{W,1}$ = 107,260
	$A_{D,2}$ = 41.112	$A_{W,2}$ = 49.945	$R_{L,2}$ = 4290.4	$R_{G,2}$ = 17.162	$Q_{W,2}$ = 107,260
	Total: 77.972	99.890	8580.8	34.324	214,520

Cooling Tower Characteristic
KaY/L = 1.24

Water/Gas Rate in Tower
R_L/R_A = 2.12

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	140	144	149	153	159	165	168	166	161	154	147	141
$T_{2,i}$	94	100	105	107	111	115	118	116	113	109	103	97
$T_{2,o}$	280	288	295	298	303	308	312	310	306	300	292	284
$T_{X,2}$	129	137	145	150	159	167	172	170	163	152	142	132
$T_{3,i}$	87	96	103	105	112	116	119	118	114	108	101	91
$T_{3,o}$	271	283	292	295	304	310	314	312	307	299	289	276
t_c (avg)	74	82	88	89	94	97	99	98	95	92	86	78
t_h (avg)	110	117	123	125	132	137	141	139	134	128	120	112
Q_{W1}	159160	152240	152240	159160	166080	173000	173000	173000	166080	155700	152240	152240
Q_{W2}	145320	141860	145320	155700	162620	176460	183380	179920	169540	152240	141860	141860
Total Q_W	304480	294100	297560	314860	328700	349460	356380	352920	335620	307940	294100	294100
Total air fan energy (kw-hr/1000 lb)	1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014	1.014
Tower fan energy (kw-hr/1000 lb)	0.557	0.557	0.557	0.557	0.557	0.557	0.557	0.557	0.557	0.557	0.557	0.557
Circulation pump energy (kw-hr/1000 lb)	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844	0.844
Compression energy (kw-hr/1000 lb)	543.697	548.621	552.561	553.875	557.486	560.113	562.083	561.098	558.799	555.52	551.248	545.995
Water consumed (gal/1000 lb)	24.198	23.809	24.829	27.210	29.640	32.215	33.430	32.555	30.272	26.579	24.198	23.275

(continued)

TABLE 2-20 (Farmington, N.M.) (Concluded)

Design intermediate temperature T_x = all wet

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1} = 0$	$A_{W,1} = 64.223$	$R_{L,1} = 23804.8$	$R_{G,1} = 47.610$	$Q_{W,1} = 595,120$	Cooling Tower Characteristic KaY/L = 1.24
	$A_{D,2} = 0$	$A_{W,2} = 66.098$	$R_{L,2} = 26434.4$	$R_{G,2} = 52.869$	$Q_{W,2} = 660,860$	Water/Gas Rate in Tower $R_L/R_A = 2.12$
	Total: 0	130.321	50239.2	100.479	1,255,980	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{x,1}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{2,i}$	89	95	98	99	101	104	108	106	103	100	97	90
$T_{2,o}$	273	281	285	287	289	294	299	296	292	288	284	275
$T_{x,2}$	273	281	285	287	289	294	299	296	292	288	284	275
$T_{3,i}$	84	91	96	97	101	103	107	105	102	99	95	87
$T_{3,o}$	267	276	283	284	289	292	298	295	291	287	281	271
t_c (avg)	71	77	82	83	86	88	92	90	87	84	80	73
t_h (avg)	97	103	107	108	110	114	118	116	112	109	106	99
Q_{W1}	664320	643560	633180	629720	622800	612420	598580	605500	615880	626260	636640	660860
Q_{W2}	653940	657400	653940	657400	650480	660860	664320	660860	657400	653940	653940	650480
Total Q_W	1318260	1300960	1287120	1287120	1273280	1273280	1262900	1266360	1273280	1280200	1290580	1311340
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894
Circulation pump energy (kw-hr/1000 lb)	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472
Compression energy (kw-hr/1000 lb)	551.335	555.684	558.361	559.030	561.037	562.710	565.386	564.048	562.040	560.034	557.692	552.674
Water consumed (gal/1000 lb)	99.570	101.562	102.131	108.105	111.519	116.355	116.924	116.640	112.372	107.536	102.984	99.570

TABLE 2-21 CALCULATIONS ON INTERSTAGE COOLING OF A HYDROGEN COMPRESSOR HANDLING 1000 LB H_2/HR

AT CASPER, WYOMING

Design intermediate temperature T_x = 115°F (all dry)

Design	ft²/1000 lb	ft²/1000 lb	lb/1000 lb	gpm/1000 lb		
						Cooling Tower Characteristic KaY/L = 1.17
	$A_{D,1}$ = 101.220	$A_{W,1}$ = 0	$R_{L,1}$ = 0	$R_{G,1}$ = 0	$Q_{W,1}$ = 0	Water/Gas Rate in Tower
	$A_{D,2}$ = 107.568	$A_{W,2}$ = 0	$R_{L,2}$ = 0	$R_{G,2}$ = 0	$Q_{W,2}$ = 0	R_L/R_A = 2.24
	Total: 208.788	0	0	0	0	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	50	52	58	66	77	87	92	92	82	71	58	56
$T_{2,i}$	50	52	58	66	77	87	92	92	82	71	58	56
$T_{2,o}$	221	224	232	243	257	271	277	277	264	249	232	229
$T_{X,2}$	42	44	50	59	72	83	89	89	77	65	50	48
$T_{3,i}$	42	44	50	59	72	83	89	89	77	65	50	48
$T_{3,o}$	211	213	221	233	251	265	273	273	257	241	221	219
t_c (avg)	-	-	-	-	-	-	-	-	-	-	-	-
t_h (avg)	-	-	-	-	-	-	-	-	-	-	-	-
Q_{W1}	0	0	0	0	0	0	0	0	0	0	0	0
Q_{W2}	0	0	0	0	0	0	0	0	0	0	0	0
Total Q_W	0	0	0	0	0	0	0	0	0	0	0	0
Total air fan energy (kw-hr/1000 lb)	2.714	2.714	2.714	2.714	2.714	2.714	2.714	2.714	2.714	2.714	2.714	2.714
Tower fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Circulation pump energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Compression energy (kw-hr/1000 lb)	525.657	526.999	531.024	536.727	544.778	551.822	551.822	555.512	548.132	540.417	531.024	529.682
Water consumed (gal/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0

(continued)

TABLE 2-21 (Casper, Wyoming) (Continued)

Design intermediate temperature $T_x = 160°F$

Design

	$ft^2/1000$ lb	$ft^2/1000$ lb	lb/1000 lb	gpm/1000 lb		Cooling Tower Characteristic
	$A_{D,1} = 48.149$	$A_{W,1} = 45.496$	$R_{L,1} = 7058.4$	$R_{G,1} = 14.117$	$Q_{W,1} = 176{,}460$	KaY/L = 1.17
	$A_{D,2} = 52.516$	$A_{W,2} = 45.496$	$R_{L,2} = 7058.4$	$R_{G,2} = 14.117$	$Q_{W,2} = 176{,}460$	Water/Gas Rate in Tower
	Total: 100.665	90.992	14116.8	28.234	352,920	$R_L/R_A = 2.24$

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	113	114	118	124	133	140	144	143	136	128	118	117
$T_{2,i}$	74	76	82	88	94	99	101	100	96	90	82	80
$T_{2,o}$	253	256	264	272	280	287	289	288	283	275	264	261
$T_{X,2}$	96	98	105	113	125	135	139	138	129	119	105	102
$T_{3,i}$	68	70	78	83	91	97	99	98	94	87	78	74
$T_{3,o}$	245	248	259	265	276	284	287	285	280	271	259	253
t_c (avg)	61	63	71	76	82	86	88	87	84	78	71	68
t_h (avg)	77	79	86	92	100	106	108	107	102	94	86	83
Q_{W1}	134940	131480	124560	124560	134940	141860	148780	148780	138400	131480	124560	128020
Q_{W2}	96880	96880	93420	103800	117640	131480	138400	138400	121100	110720	93420	96880
Total Q_W	231820	228360	217980	228360	252580	273340	287180	287180	259500	242200	217980	224900
Total air fan energy (kw-hr/1000 lb)	1.309	1.309	1.309	1.309	1.309	1.309	1.309	1.309	1.309	1.309	1.309	1.309
Tower fan energy (kw-hr/1000 lb)	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251
Circulation pump energy (kw-hr/1000 lb)	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695
Compression energy (kw-hr/1000 lb)	530.892	532.205	536.802	540.413	545.010	548.621	549.935	549.278	546.652	542.383	536.802	534.832
Water consumed (gal/1000 lb)	15.585	15.283	15.888	18.082	21.940	23.832	26.404	26.404	22.243	19.746	15.888	16.493

(continued)

TABLE 2-21 (Casper, Wyoming) (Concluded)

Design intermediate temperature T_x = all wet

Design	ft²/1000 lb	ft²/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1} = 0$	$A_{W,1} = 64.223$	$R_{L,1} = 23804.8$	$R_{G,1} = 47.610$	$Q_{W,1} = 595,120$	Cooling Tower Characteristic KaY/L = 1.17
	$A_{D,2} = \underline{0}$	$A_{W,2} = \underline{66.098}$	$R_{L,2} = \underline{26434.4}$	$R_{G,2} = \underline{52.869}$	$Q_{W,2} = \underline{660,860}$	Water/Gas Rate in Tower $R_L/R_A = 2.24$
	Total: 0	130.321	50239.2	100.479	1,255,980	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{2,i}$	89	92	96	101	103	105	107	106	103	101	96	94
$T_{2,o}$	273	277	283	289	292	295	298	296	292	289	283	280
$T_{X,2}$	273	277	283	289	292	295	298	296	292	289	283	280
$T_{3,i}$	86	89	93	100	102	104	106	105	101	100	93	91
$T_{3,o}$	269	273	279	288	291	294	296	295	289	288	279	276
t_c (avg)	72	75	79	85	87	89	91	90	87	85	79	77
t_h (avg)	98	101	105	110	112	115	117	116	112	110	105	103
Q_{W1}	664320	653940	640100	622800	615880	608960	602040	605500	615880	622800	640100	647020
Q_{W2}	647020	650480	657400	653940	657400	660860	664320	660860	660860	653940	657400	653940
Total Q_W	1311340	1304420	1297500	1276740	1273280	1269820	1266360	1266360	1276740	1276740	1297500	1300960
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894
Circulation pump energy (kw-hr/1000 lb)	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472
Compression energy (kw-hr/1000 lb)	553.499	555.512	558.196	562.221	563.563	564.905	566.247	565.576	563.228	562.221	558.196	556.854
Water consumed (gal/1000 lb)	98.813	98.813	102.314	104.468	109.045	113.891	115.776	115.776	111.737	106.622	102.314	102.044

TABLE 2-22 CALCULATIONS ON INTERSTAGE COOLING OF A HYDROGEN COMPRESSOR HANDLING 1000 LBS H_2/HR AT BEULAH, NORTH DAKOTA

Design intermediate temperature T_x = 115°F (all dry)

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb	
$A_{D,1}$ = 116.583	$A_{W,1}$ = 0	$R_{L,1}$ = 0	$R_{G,1}$ = 0	$Q_{W,1}$ = 0	Cooling Tower Characteristic KaY/L = --
$A_{D,2}$ = 112.931	$A_{W,2}$ = 0	$R_{L,2}$ = 0	$R_{G,2}$ = 0	$Q_{W,2}$ = 0	Water/Gas Rate in Tower R_L/R_A = --
Total: 239.514	0	0	0	0	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	29	36	45	62	74	81	89	87	76	65	48	39
$T_{2,i}$	29	36	45	62	74	81	89	87	76	65	48	39
$T_{2,o}$	193	203	215	237	253	263	273	271	256	241	219	207
$T_{X,2}$	20	27	37	56	69	78	85	83	71	59	41	30
$T_{3,i}$	20	27	37	56	69	78	85	83	71	59	41	30
$T_{3,o}$	18	191	204	229	247	259	268	265	249	233	209	195
t_c (avg)	-	-	-	-	-	-	-	-	-	-	-	-
t_h (avg)	-	-	-	-	-	-	-	-	-	-	-	-
Q_{W1}	0	0	0	0	0	0	0	0	0	0	0	0
Q_{W2}	0	0	0	0	0	0	0	0	0	0	0	0
Total Q_W	0	0	0	0	0	0	0	0	0	0	0	0
Total air fan energy (kw-hr/1000 lb)	3.113	3.113	3.113	3.113	3.113	3.113	3.113	3.113	3.113	3.113	3.113	3.113
Tower fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Circulation pump energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Compression energy (kw-hr/1000 lb)	512.064	516.768	523.152	535.248	543.648	549.024	554.064	552.720	544.992	537.264	525.504	518.784
Water consumed (gal/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0

(continued)

TABLE 2-22 (Continued)

Design intermediate temperature $T_x = 160°F$

Design	ft²/1000 lb	ft²/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1} = 50.887$	$A_{W,1} = 45.496$	$R_{L,1} = 7058.4$	$R_{G,1} = 14.117$	$Q_{W,1} = 176,460$	Cooling Tower Characteristic KaY/L = 1.30
	$A_{D,2} = \underline{55.312}$	$A_{W,2} = \underline{45.496}$	$R_{L,2} = \underline{7058.4}$	$R_{G,2} = \underline{14.117}$	$Q_{W,2} = \underline{176,460}$	Water/Gas Rate in Tower $R_L/R_A = 1.85$
	Total: 106.199	90,992	14,117	28.234	352,920	

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	97	102	108	121	129	136	140	139	131	123	111	104
$T_{2,i}$	64	67	74	85	92	98	100	98	93	87	77	68
$T_{2,o}$	240	244	253	268	277	285	288	285	279	271	257	245
$T_{X,2}$	77	83	92	110	121	130	136	134	123	113	96	85
$T_{3,i}$	59	62	69	82	89	95	98	96	91	84	73	63
$T_{3,o}$	233	237	247	264	273	281	285	283	276	267	252	239
t_c (avg)	54	56	63	74	80	86	88	85	82	76	67	57
t_h (avg)	67	70	77	90	97	104	107	105	99	92	81	71
Q_{W1}	115,300	123,700	121,300	126,100	132,100	134,500	139,300	145,300	130,800	126,100	117,600	126,100
Q_{W2}	61,200	72,000	76,700	96,000	109,200	116,300	127,100	130,800	109,200	98,400	76,700	74,400
Total Q_W	176,500	195,700	198,000	222,100	241,300	250,800	266,400	276,100	240,000	224,500	194,300	200,500
Total air fan energy (kw-hr/1000 lb)	1.381	1.381	1.381	1.381	1.381	1.381	1.381	1.381	1.381	1.381	1.381	1.381
Tower fan energy (kw-hr/1000 lb)	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251	0.251
Circulation pump energy (kw-hr/1000 lb)	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695	0.695
Compression energy (kw-hr/1000 lb)	536.928	538.944	543.648	551.712	556.416	560.448	562.128	560.784	557.424	553.056	546.000	539.616
Water consumed (gal/1000 lb)	9.44	11.73	13.05	17.56	20.81	23.19	25.17	13.45	21.16	18.19	13.08	12.09

(continued)

TABLE 2-22 (Concluded)

Design intermediate temperature T_x = all wet

Design	ft^2/1000 lb	ft^2/1000 lb	lb/1000 lb	gpm/1000 lb		
	$A_{D,1}$ = 0	$A_{W,1}$ = 64.223	$R_{L,1}$ = 23,805	$R_{G,1}$ = 47.61	$Q_{W,1}$ = 595,120	Cooling Tower Characteristic KaY/L = 1.30
	$A_{D,2}$ = 0	$A_{W,2}$ = 66.098	$R_{L,2}$ = 26,434	$R_{G,2}$ = 52.87	$Q_{W,2}$ = 660,860	Water/Gas Rate in Tower
	Total: 0	130.321	50,239	100.48	1,255,980	R_L/R_A = 1.85

Month	1	2	3	4	5	6	7	8	9	10	11	12
$T_{1,o}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{X,1}$	281	281	281	281	281	281	281	281	281	281	281	281
$T_{2,i}$	75	84	87	95	99	105	107	105	101	96	91	84
$T_{2,o}$	255	267	271	281	287	295	297	295	289	283	276	267
$T_{X,2}$	255	267	271	281	287	295	297	295	289	283	276	267
$T_{3,i}$	71	81	85	94	98	104	106	104	100	95	89	82
$T_{3,o}$	249	263	268	280	285	294	296	294	288	281	273	264
t_c (avg)	57	66	70	79	83	89	91	89	85	80	74	67
t_h (avg)	84	93	96	105	109	114	116	114	110	106	100	93
Q_{W1}	713,000	687,800	671,900	641,900	630,700	613,900	608,200	613,900	625,100	639,100	660,600	680,300
Q_{W2}	633,000	646,700	646,700	648,600	655,200	660,900	660,900	660,900	655,200	652,400	649,600	643,900
Total Q_W	1346,000	1334,500	1318,600	1291,500	1285,900	1274,800	1269,100	1274,800	1280,300	1291,500	1310,200	1324,200
Total air fan energy (kw-hr/1000 lb)	0	0	0	0	0	0	0	0	0	0	0	0
Tower fan energy (kw-hr/1000 lb)	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894	0.894
Circulation pump energy (kw-hr/1000 lb)	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472	2.472
Compression energy (kw-hr/1000 lb)	544.656	551.040	553.392	559.104	561.792	565.824	567.168	565.824	563.136	559.776	556.080	551.376
Water consumed (gal/1000 lb)	91.93	94.87	97.80	105.3	113.3	125.5	120.0	119.6	113.4	106.9	100.0	95.16

TABLE 2-23 SUMMARY OF WET/DRY COMPRESSOR INTER-STAGE COOLING FOR HYDROGEN COMPRESSORS

Farmington, New Mexico

Basis: 1000 lb hydrogen compressed/hr.

Design intermediate temp., F	all dry	140	160	180	all wet
Dry cooler area, ft^2/1000 lb/hr	217.744	136.030	102.511	77.972	0
Wet cooler area, ft^2/1000 lb/hr	0	80.200	90.992	99.890	130.321
Circulation rate, gpm/1000 lb/hr	0	17.1616	28.234	34.324	100.479
Avg. fan & pump energy, $\frac{\text{kw-hr}}{\text{1000 lb}}$	2.831	2.343	2.279	2.415	3.366
Compression energy, kw-hr/1000 lb	531.738	538.224	553.723	554.258	559.169
Water consumed, gal/1000 lb	0	10.3	20.9	27.7	107

Casper, Wyoming

Basis: 1000 lb hydrogen compressed/hr.

Design intermediate temp., F	all dry	160	all wet
Dry cooler area, ft^2/1000 lb/hr	208.788	100.665	0
Wet cooler area, ft^2/1000 lb/hr	0	90.992	130.321
Circulation rate, gpm/1000 lb/hr	0	28.234	100.479
Avg. fan & pump enery, $\frac{\text{kw-hr}}{\text{1000 lb}}$	2.714	2.255	3.366
Compression energy, kw-hr/1000 lb	539.466	541.152	560.852
Water consumed, gal/1000 lb	0	19.8	107

Beulah, North Dakota

Basis: 1000 lb hydrogen compressed/hr.

Design intermediate temp., F	all dry	160	all wet
Dry cooler area, ft^2/1000 lb/hr	239.514	106.199	0
Wet cooler area, ft^2/1000 lb/hr	0	90.992	130.321
Circulation rate, gpm/1000 lb/hr	0	28.234	100.48
Avg. fan & pump energy, $\frac{\text{kw-hr}}{\text{1000 lb}}$	3.113	2.327	3.366
Compression energy, kw-hr/1000 lb	534.436	550.592	558.264
Water consumed, gal/1000 lb	0	16.6	107

2.5 TURBINE CONDENSERS IN STEAM-ELECTRIC POWER PLANTS

2.5.1 Introduction

In a steam-electric power plant utilizing an all evaporative cooling system, the water consumed for cooling is always a large amount and can amount to more than 90 percent of the total water consumption. In Farmington, New Mexico, for example, maximum evaporation occurs in July with an evaporative tower loss of 0.46 gal/kw-hr*; the average annual evaporation rate is 0.41 gal/kw-hr or 14,400 gal/cal min (20.7 x 10^6 gal/cal day) for a 3000 Mwe plant operating at a load factor of 70 percent. The maximum evaporation loss from a cooling tower situated in Beulah, North Dakota also occurs in July and is 0.42 gal/kw-hr with an average annual evaporation rate of 0.39 gal/kw-hr or 13,700 gal/cal min (19.7 x 10^6 gal/cal day) for a 3000 Mwe plant operating at a load factor of 70 percent.

In the water short regions of the West dry cooling systems such as mechanical-draft finned-tube heat exchangers may offer a viable alternative. In the broadest way dry cooling requires a larger capital investment than wet cooling and also requires that the unrecovered heat be thrown away at a higher temperature. Offsetting the increased capital costs and decreased thermal efficiency is a savings in water consumed and its cost and the cost of treatment. As we have pointed out previously, the choice of cooling is an economic one. In the previous study[1] we showed that if the cost of water exceeds about $4.20 to $5.00 per 1000 gallons of evaporated water, then an all dry cooling system should be selected. If the actual cost of water is less than $4.20 - $5.00/1000 gal, then all wet cooling or a combination of wet/dry cooling should be selected. We showed that for Navajo/Farmington, New Mexico, a wet/dry cooling system would be more economical than all wet cooling if water costs more than about $2.50/1000 gal.

In Reference 1 we also made some estimates of the actual cost of water. We have shown that if the plant is located about twenty miles from the water source, the cost of water is equally dependent upon the cost of transporting water to the site and the cost of water treatment and disposal. The total water cost for this case is approximately $0.50 per 1000 gallons. We assumed that all water rights have been obtained at a negligible cost. Under these conditions all wet cooling would be desirable. However, at a distance greater than about fifty miles from the water source the water cost is primarily dependent on the cost of transporting water. In the West the cost of transporting water by a pipeline or aqueduct is about 1-2¢ per thousand gallons per mile.

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*kw-hr generated

It is unlikely that water would be transported over 100 miles to the plant so that the actual cost of water would not exceed $2.00 per thousand gallons. Under this condition a combination wet/dry cooling system would be economically comparable to an all wet system. The main advantage is that the savings in total water consumed in the wet/dry system would be about 75% of the total water consumed for an all wet cooling system under optimum economic conditions. Moreover, in water short areas the total consumptive use might well determine the choice of a cooling system, regardless of the cost of water. Thus, it is important to analyse in some detail the wet/dry cooling system.

It is clear that large changes in water consumption will occur at relatively modest costs for water. The previous set of calculations for wet/dry cooling reported in Reference 1 was limited to one set of calculations and does not show, for example, the sensitivity to the cost of money nor the sensitivity to climate. In the present study we have updated the equipment costs and varied both the amortization rate and fuel charge. Within the Western states only two climates need be studied: New Mexico on one hand and Wyoming, Montana or North Dakota on the other hand. We have repeated the calculations for Navajo/Farmington, New Mexico presented in Reference 1 but with the variations pointed out above and extended the calculations to a power plant located in Beulah, North Dakota.

We are interested in comparing the costs of a wet/dry cooling system to an all wet cooling system so that the differences in costs, rather than the absolute costs, are of primary concern.

2.5.2 Operation and Costs of Wet/Dry Cooling System

In Section 4 of Reference 1 we described in some detail the performance and costs associated with all wet, all dry and combination wet/dry cooling systems. In this section we will briefly summarize the major costs.

The following costs were considered in the study:

Capital cost of cooling system: Includes the capital expenditures for installation and materials necessary to construct the cooling system.

Annual capital cost: An annual fixed charge rate is applied to the capital cost of the cooling system to determine the annual cost of interest, amortization and other charges incidental to the acquisition and use of the initial capital expense.

Annual cost of operation and maintenance: This is the cost of operating and maintaining the cooling system and is taken to be one percent of the capital cost of the cooling system.

Annual credit for excess power generation: The turbine generator is assumed to operate 6132 hours per year at constant throttle full-load conditions except when it is throttled back to avoid exceeding the specified back pressure limit of the unit. At some ambient conditions the turbine may generate a greater output than the nominal generating output. The annual credit for excess power generation is the product of the average fuel cost per kw-hr and the excess energy generated.

Annual cost of replacement energy: Sufficient peaking capacity must be installed for the ten highest temperature hours of the year. Above a temperature of 82°F replacement energy is assumed to come from installed gas turbine units at a fuel cost of 35 mills/kw-hr and below this temperature replacement energy is provided by excess capability available elsewhere in the utility system at a fuel cost of 6 mills/kw-hr. The capital cost of replacement capacity is assumed to be $175/max kw; the annual replacement capacity cost is based on the capital cost at the annual fixed charge rate.

Annual cost of auxiliary power: This is the cost of the power necessary to run the cooling system. The incremental cost of sufficient additional plant capacity to provide the auxiliary power required is assumed to be $922/max kw with the annual cost based on the annual fixed charge rate and the capital cost.

Annual fuel cost: The unit fuel cost was varied from $\$0.50/10^6$ Btu to $\$1.50/10^6$ Btu.

Annual cost of water: Includes the cost of supplying the makeup water, the cost of treatment of the makeup and/or the circulating water in the tower, and the cost of treatment and disposal of the blowdown in an environmentally acceptable manner. It was assumed that the makeup water was 20 percent more than the evaporation rate to allow for blowdown and drift. The water costs are expressed in $/1000 gallons of water evaporated.

Total annual cost: This cost is the algebraic sum of all of the annual costs discussed above.

A summary of the unit price data used in this study is found in Table 2-24. The unit price data used in Reference 1 is also shown for comparison.

TABLE 2-24 SUMMARY OF UNIT PRICE DATA

	Ref. 1	Present Study
Annual Fixed Charge Rate (percent)	15	15, 18, 21
Unit Fuel Cost ($\$/10^6$ Btu)	0.50	0.50, 1.00, 1.50
Replacement Capacity Charge Above 82°F ($/maximum kw)	175	175
Replacement Capacity Charge Below 82°F ($/maximum kw)	0	0
Replacement Energy Cost At and Above 82°F (mills/kwh)	35	35
Replacement Energy Cost Below 82°F (mills/kwh)	6	6
Auxiliary Power Capital Cost ($/maximum)	400	922
Auxiliary Energy Cost	*	*
Interest During Construction (percent)	8	8
Site Construction Cost Index		
Materials	0.989	0.976
Labor	0.850	0.841
Construction Period (years)	2	2
Scheduled Start-up (year)	1977	1978

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*Based on average fuel cost plus operation and maintenance. O&M is 4% of average fuel cost.

Figure 2-25 was analyzed to show the effect of makeup water requirements on the evaluated costs of the cooling system. The cooling system uses a conventional mechanical draft wet tower and a separate conventional mechanical draft dry tower; the cooling water for each tower flows in separate circuits. The dry tower operates during the whole year with its greatest operating efficiency in winter while the evaporation tower operates in warmer weather during periods of peaking. The evaporative tower operates only when the turbine back pressure exceeds a maximum operating pressure with the dry tower alone. Calculations for the wet/dry tower were run for four different maximum operating pressures: 5.0, 4.5, 4.0 and 3.5 inches of Hg. Calculations were also performed for an all wet cooling system. For the all wet system a design back pressure was specified; the turbine condenser can operate at pressures higher than the design back pressure. The design back pressures that were selected are: 4.5, 4.0 and 3.5 inches of Hg.

The wet/dry and all wet tower calculations were done by R. W. Beck and Associates, as described in Reference 1. Figures 2-26 and 2-27 show the optimum evaluated costs as a function of the fraction of water consumed for all wet cooling for a range of water costs and for a typical set of fixed charges and fuel costs. For the all wet system the optimum total evaluated cost was taken to be the lowest cost within the range of design pressures considered. The optimum cost for the wet/dry system at a given evaporation rate was taken to be the lowest cost within the range of maximum operating pressures considered. In all cases if a true minimum was not found within the range of pressures, the variation in costs with pressure was fairly small indicating that the true minimum was fairly insensitive to the design or maximum operating pressure.

We are primarily concerned on the dependence of the changeover water cost on the fixed charge rate, fuel cost and site. The changeover water cost is the cost of water above which wet/dry cooling is more economical than all wet cooling (or below which all wet cooling is more economical than wet/dry cooling). For example, the changeover water cost at Navajo/Farmington, New Mexico is $3.83/1000 gal water evaporated (see Figure 2-26) and at Beulah, North Dakota is $3.60/1000 gal water evaporated (see Figure 2-27). We will not present nor discuss the breakdown of the operating costs, for example, into the annual cost of replacement energy or auxiliary power. These are presented in some detail for a large number of sites in a recently released EPA report by United Engineers and Constructors, Inc.[5].

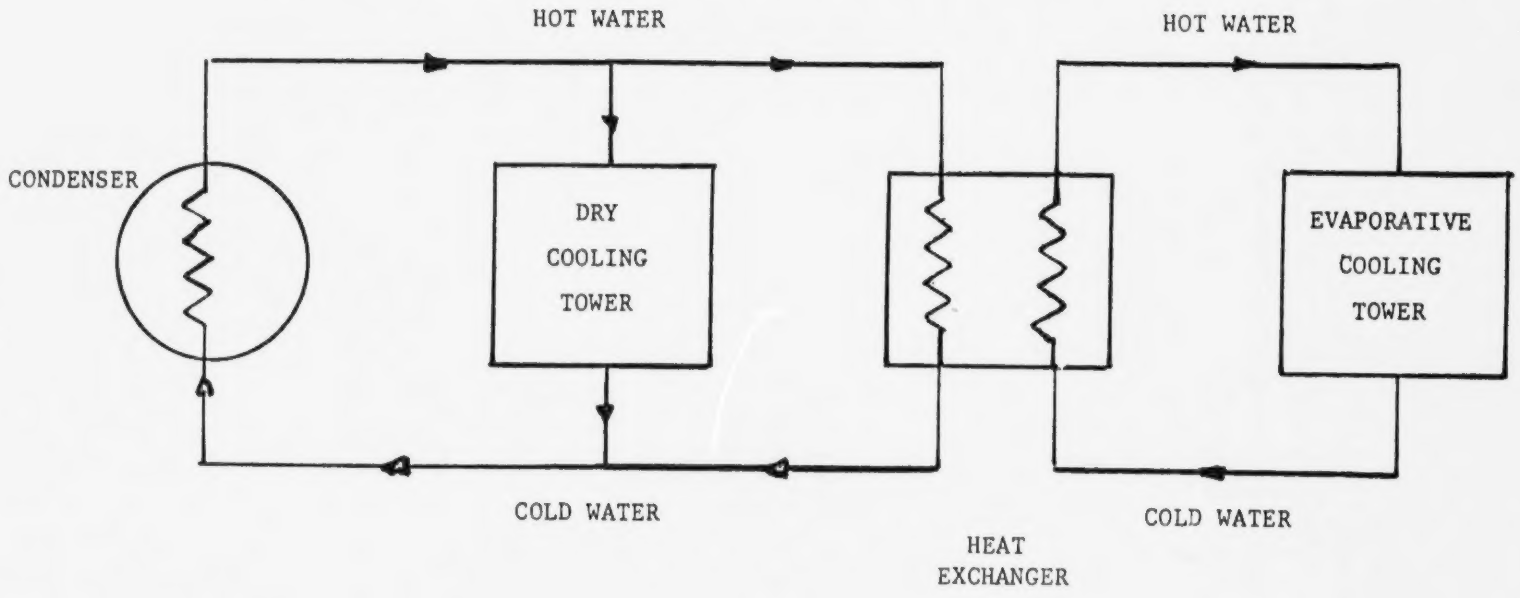
HOT WATER
HOT WATER
CONDENSER
DRY
COOLING
TOWER
EVAPORATIVE
COOLING
TOWER
COLD WATER
COLD WATER
HEAT
EXCHANGER

Fig. 2-25. Wet/dry cooling system.

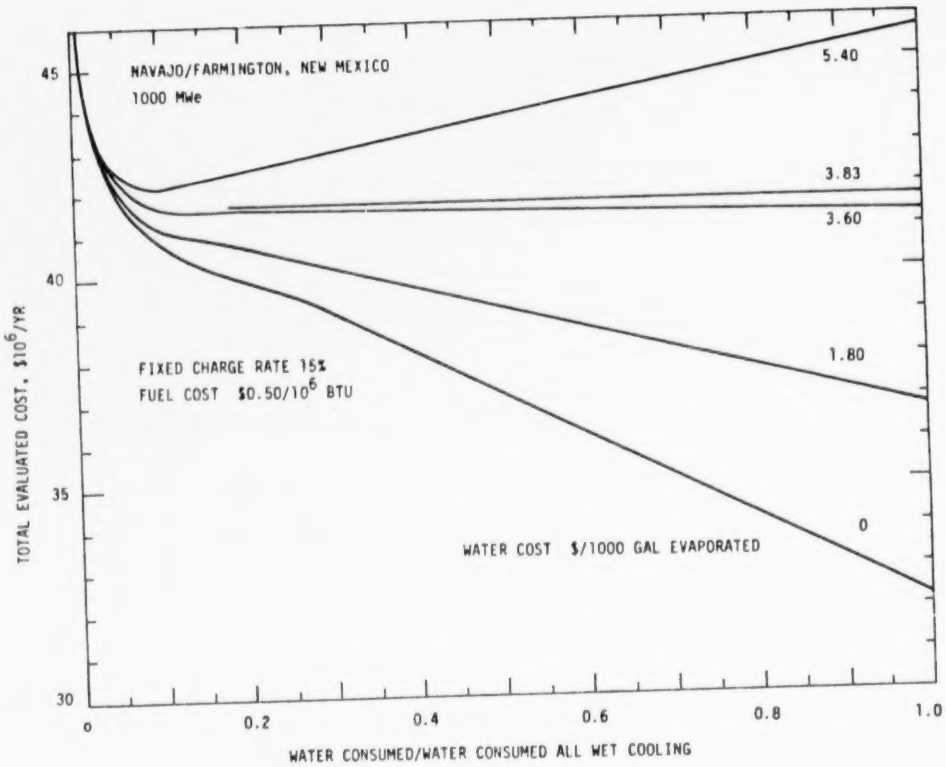

Figure 2-26. Total annual evaluated cost of wet/dry cooling system located at Navajo/Farmington, New Mexico.

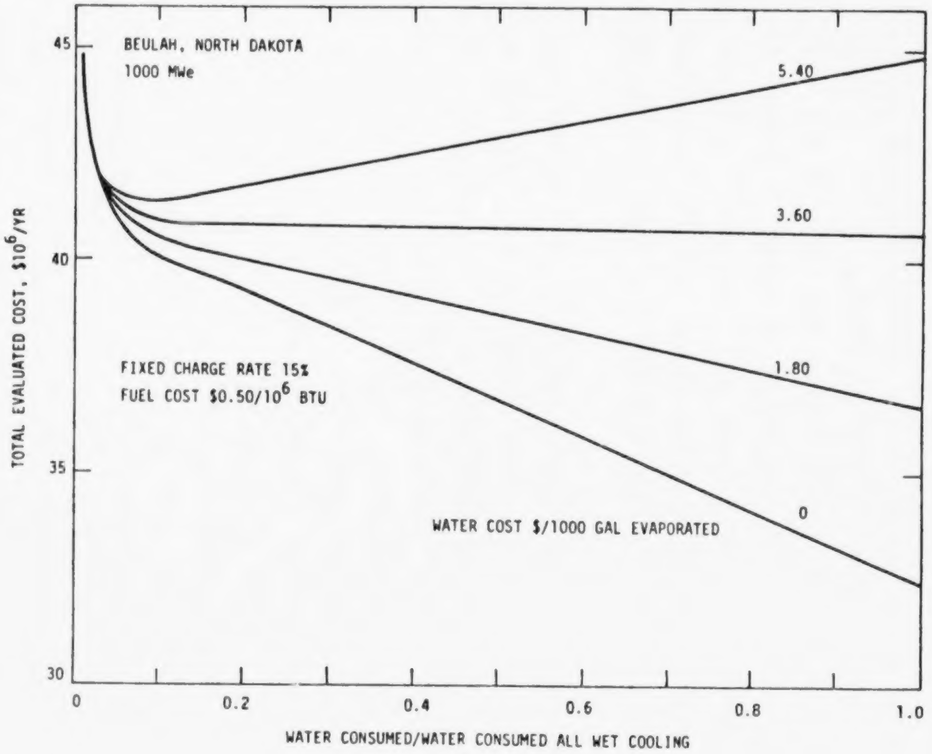

Figure 2-27. Total annual evaluated cost of wet/dry cooling system located at Beulah, North Dakota

The changeover water costs are listed in Table 2-25 and shown graphically in Figure 2-28 for Farmington, New Mexico and Beulah, North Dakota as a function of both the fixed charge rate and the fuel cost. The changeover water costs range from \$3.65 to \$5.47 per 1000 gals water evaporated in North Dakota and \$3.83 to \$5.87 per 1000 gals water evaporated in New Mexico for the fixed charge rates and fuel costs considered. We should point out that in Reference 1 the changeover water cost for New Mexico was found to be \$2.50/1000 gal and should be compared to the lowest value cited above, namely \$3.83/1000 gals. The difference can be attributed to the higher auxiliary power and cooling tower capital costs used in the present study.

For a given fixed charge rate and fuel cost the ratio of the changeover water cost at New Mexico to that at North Dakota is shown in Figure 2-29. In every case the ratio does not exceed 7.5 percent. The slightly higher changeover water costs for New Mexico reflects the longer periods of peaking with the concomitant larger and more expensive wet cooling tower and the higher annual costs of replacement energy.

The variation in the changeover water cost with fixed charge rate is shown in Figure 2-30 for various fuel costs. For a given fuel cost the ratio of the changeover water cost at a fixed charge rate to the changeover water cost at a fixed charge rate of 15 percent is shown. The fixed charge ratio is the ratio of the fixed charge to the fixed charge of 15 percent. For example, in New Mexico for a fuel cost of $\$1.50/10^6$ Btu and a fixed charge rate of 21 percent (fixed charge ratio is 21/15 = 1.4), the changeover water cost ratio is (5.87/4.34) = 1.35. Also shown in Figure 2-30 is a line with a slope of unity corresponding to the case where the water cost varies as the fixed charge rate. The figure shows that the variation in the changeover water cost is primarily dependent on the fixed charge rate and relatively independent of the fuel cost.

In a similar manner the variation in the changeover water cost with fuel cost ratio is shown in Figure 2-31 for various fixed charge rates. The fuel cost ratio is the ratio of the fuel cost to the fuel cost of $\$0.50/10^6$ Btu. Also shown is a line with a slope of unity corresponding to the case where the water cost varies as the fuel cost. It is seen, as pointed out above, that the water cost is relatively insensitive to the fuel cost, i.e. for a threefold variation in the fuel cost, the changeover water cost does not vary by more than 17 percent. The wet/dry cooling system operates at a slightly greater turbine back pressure (higher condensing temperature) with a slightly higher fuel cost.

TABLE 2-25 CHANGEOVER WATER COSTS FOR NEW MEXICO AND NORTH DAKOTA

		Changeover Water Cost ($/1000 gals evaporated)	
Fixed Charge Rate (percent)	Fuel Cost ($/$10^6$ Btu)	Farmington New Mexico	Beulah North Dakota
15	0.50	3.83	3.65
	1.00	4.16	3.95
	1.50	4.34	4.18
18	0.50	4.43	4.22
	1.00	4.80	4.57
	1.50	5.18	4.85
21	0.50	5.03	4.82
	1.00	5.44	5.26
	1.50	5.87	5.47

We have found the changeover water cost for each set of fixed charge rate and fuel cost considered in this study. For each changeover water cost there are two cooling systems that are of particular interest. One is the optimized (with respect to cost) all evaporation cooling system and the other is the wet/dry cooling system which has the lowest annual cost and the lowest evaporation rate at the changeover water costs shown previously. The evaporation rates corresponding to both cooling systems are shown in Table 2-26. The wet/dry evaporation rate expressed as a percentage of the all wet evaporation rate is also shown in the table. For North Dakota the optimized wet/dry system has an evaporation rate in the range 12 to 15 percent for all of the cases considered, while for New Mexico the range is 11 to 15 percent at the lowest fixed charge rate and increases to 18 to 22 percent at the highest fixed charge rate. Other systematic variations are not evident. This can be attributed to the fact that the calculational procedure was set up to determine the tower conditions corresponding to the optimum or minimum annual evaluated cost. In the vicinity of the optimum cost, the annual costs are fairly

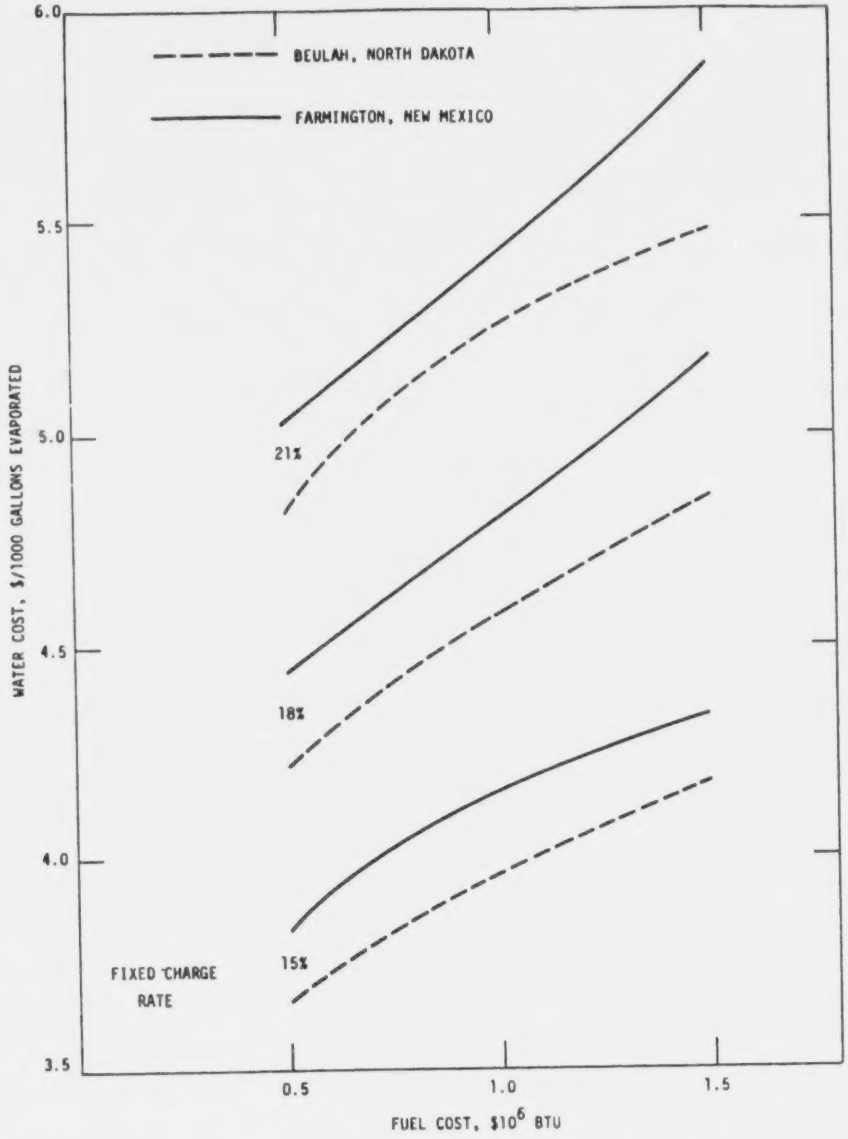

Figure 2-28. Changeover water costs for Beulah, North Dakota and Navajo/ Farmington, New Mexico.

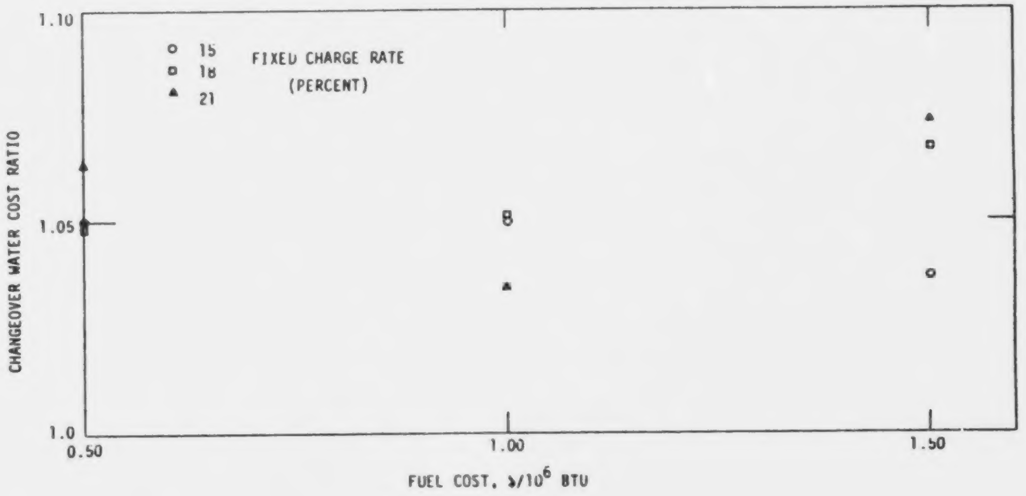

Figure 2-29. Ratio of changeover water cost at New Mexico to North Dakota.

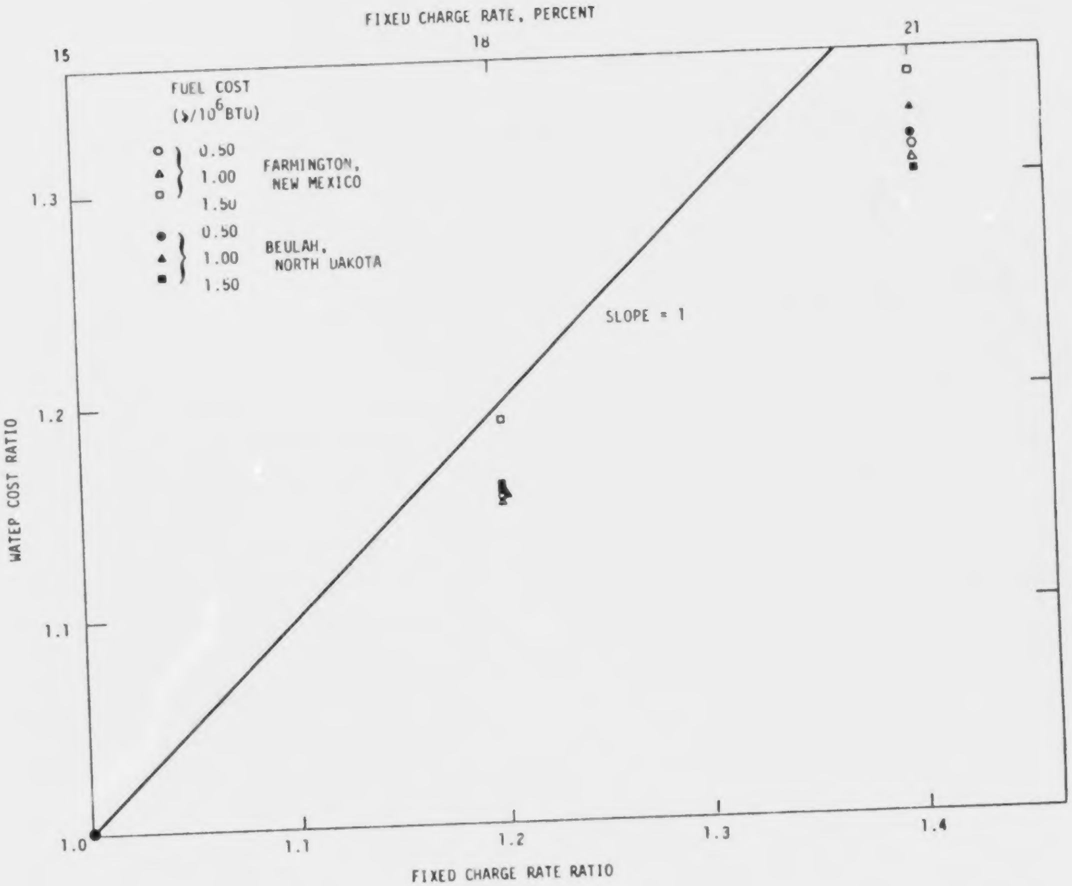

Figure 2-30. Ratio of changeover water costs as a function of fixed charge rate ratio.

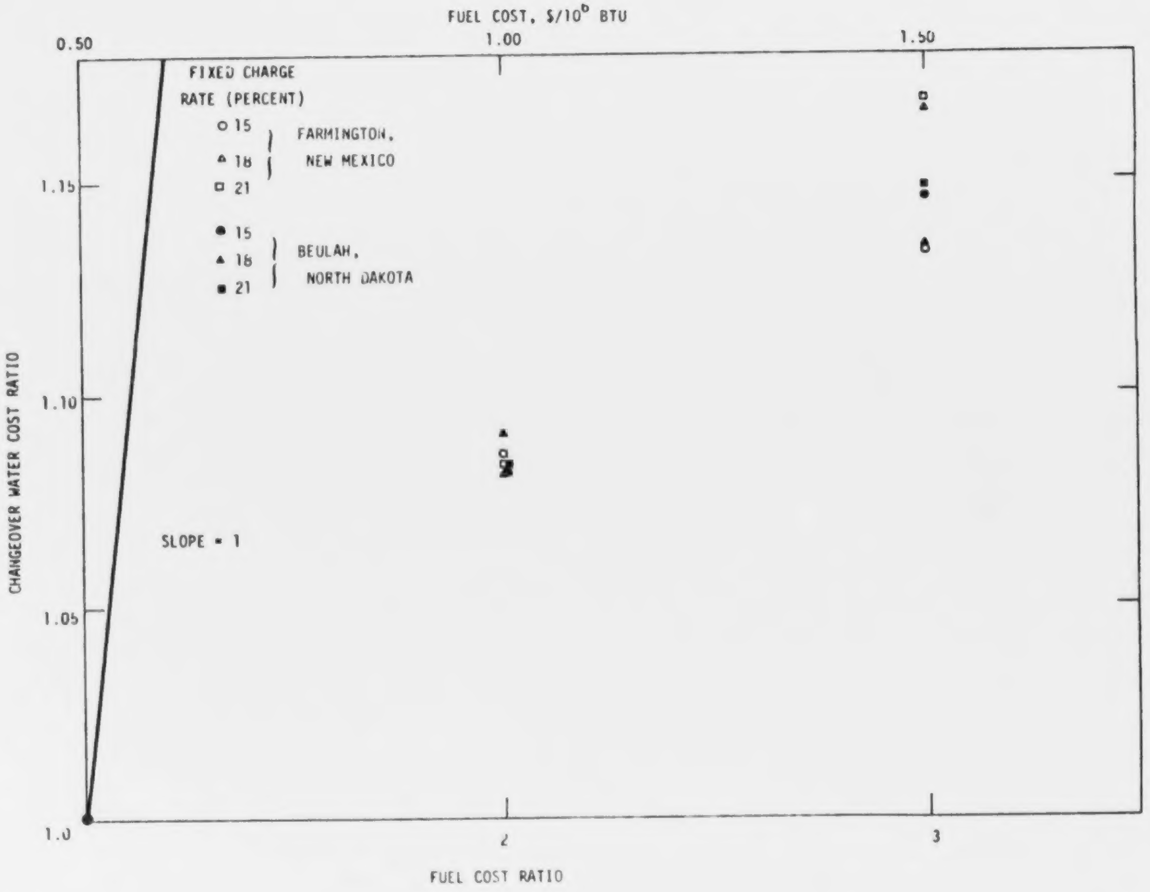

Figure 2-31. Ratio of changeover water costs as a function of fuel cost ratio.

TABLE 2-26 EVAPORATION RATE FOR OPTIMIZED WET/DRY AND ALL WET COOLING SYSTEMS

Fixed Charge Rate (Percent)	Fuel Cost ($\$/10^6$ Btu)	Farmington, New Mexico			Beulah, North Dakota		
		Wet/Dry*	All Wet	Percent	Wet/Dry*	All Wet	Percent
15	0.50	693	4762	14.6	661	4346	15.2
	1.00	686	4762	14.4	650	4346	15.0
	1.50	534	4753	11.2	513	4346	11.8
18	0.50	847	4762	17.8	661	4426	14.9
	1.00	686	4762	14.6	650	4346	15.0
	1.50	856	4762	18.0	513	4346	11.8
21	0.50	847	4762	17.8	661	4426	14.9
	1.00	1012	4762	21.3	651	4346	15.0
	1.50	1028	4762	21.6	513	4346	11.8

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*Evaporation rate in gallons per calendar minute.

insensitive to the tower conditions. However, the wet/dry evaporation rate is very sensitive to the tower conditions, thus, a slight change in the tower conditions, although not affecting the optimum cost very much, will lead to a larger variation in the evaporation rate.

REFERENCES (Section 2)

1. Gold, H. et al, Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States." EPA Report No. 400/7-77-037, U.S. Environmental Protection Agency, Washington, D.C., February, 1977.

2. Water Purification Associates, "Water Conservation and Pollution Control in Coal Conversion Processes", EPA Report 600/7-77-065, U.S. Environmental Protection Agency, Research Triangle Park, N.C., June 1977.

3. Goldstein, D.J. and Probstein, R.F., "Water Requirements for an Integrated SNG Plant and Mine Operationg", pp 307-332 in Symposium Proceedings: Environmental Aspects of Fuel Conversion Technology, II, (December 1975, Hollywood, Florida), EPA report 600/2-76-149, U.S. E.P.A., Research Triangle Park, North Carolina 27711, June 1976.

4. Gold, H. and Goldstein, D.J., "Water Related Environmental Effects in Fuel Conversion," EPA Report 600/7-78-197a,b, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, October 1978.

5. Hu, M.C. and Englesson, G.A., "Wet/Dry Cooling System for Fossil-Fueled Power Plants: Water Conservation and Plume Abatement," Report No. EPA-600/7-77-137, Environmental Protection Agency, Research Triangle Park, N.C.,

6. Kelly's Handbook of Crossflow Cooling Tower Performance, Neil W. Kelly and Associates, Kansas City, Missouri.

7. Neerken, R.F., "Compressor Selection for the Chemical Process Industries", Chemical Engineering, 7894, January 20, 1975.

3. REGIONAL WATER REQUIREMENTS AND RESIDUALS DISPOSAL

3.1 INTRODUCTION

In Reference 1, calculations of the water requirements and wet-solid residuals were presented for three standard size coal conversion plants (Lurgi, Synthane and Synthoil) each located at four Western sites and for two oil shale plants located at one Western site. In order to extend the data base to include more plant-site combinations and provide more meaningful regional water impact assessments, results from a program recently completed by Water Purification Associates for the U.S. Environmental Protection Agency (Contract No. 68-03-2207) and the Department of Energy (Contract No. EX-76-C-01-2445) will be summarized in this section. Details of the complete study are given in Reference 2.

3.2 PROCESS AND SITE SELECTION

A total of 42 plant-site combinations were studied in the Western states. Table 3-1 lists the plant-site combinations while Figure 3-1 shows the locations of these sites with respect to the major energy reserves and the primary water resources characteristics. The map shows more sites than the ones given in Table 3-1. Primary sites correspond to the sites listed in the table and secondary sites were selected to provide a larger study area with respect to water availability. These plants were sited in the same regions as in the Technology Assessment of Western Energy Resource Development Study[1]. Plant design considerations included the following broad categories of water related process criteria: (i) low temperature gasifiers, (ii) high temperature gasifiers, (iii) coal refining and liquefaction processes, and (iv) surface retorting of oil shale. Site considerations include: water supply and alternative demands, climate and rank of coal and mine type. The water requirements and water uses within the plant, the waters to be treated within the plant and the waste effluents are dependent on the site of the coal and oil shale conversion complex, as well as on the process itself. The water control technology and disposal of the waste solid residues are dependent on the quality of the supply water, which is also site dependent. The large number of site and process combinations were studied in order to derive generalized rules as to the feasibility of siting and its subsequent environmental impact resulting from the consumptive use of water at that site.

TABLE 3-1 COAL AND OIL SHALE CONVERSION PLANT-SITE COMBINATIONS FOR WESTERN STATES

State	Mine	Water Source				Coal Gasification				Coal Liquefaction and Coal Refining		Plant-Site Combinations	
						High Temp. Gasifier		Low Temp. Gasifier					
		Surface	Ground	Mining[a]	Coal[b]	Hygas	Bigas	Lurgi	Synthane	Synthoil	SRC	No.	Total State
Montana	Decker-Dietz		X	S	S	X		X				2	
	Foster Creek	Tongue R.		S	S			X				1	
	U.S. Steel Chupp Mine	Yellowstone R.		S	L		X					1	
	East Moorhead	Powder R.		S	L	X						1	
	Pumpkin Creek	Tongue R.		S	L						X	1	
	Otter Creek		X	S	L						X	1	
	Colstrip	Yellowstone R.		S	S	X			X		X	3	
	Coalridge	Missouri River		S	L						X	1	11
New Mexico	Gallup		X	S	S	X		X		X		3	
	El Paso	San Juan R.		S	S	X		X				2	
	Wesco	San Juan R.		S	S			X				1	6
North Dakota	Scranton	Grand R.		S	L		X					1	
	Bentley	Knife R.		S	L						X	1	
	Underwood	L. Sakakawea		S	L						X	1	
	Knife River	Knife R.		S	L			X				1	
	Center	Knife R.		S	L		X					1	
	Slope	Yellowstone R.		S	L		X					1	
	Dickinson	L. Sakakawea		S	L						X	1	
	Williston	Missouri R.		S	L			X				1	8
Wyoming	Belle Ayr	Crazy Woman Cr.		S	S	X						1	
	Gillette-Wyodak	Crazy Woman Cr.		S	S	X					X	2	
	Spotted Horse Strip	Powder R.		S	S				X			1	
	Hanna	Medicine Bow		S	S	X						1	
	Antelope Creek Mine	Beaver Cr.	X	S	S	X			X		X	3	
	Lake-de-Smet	Tongue R.		S	S					X		1	
	Kemmerer	Hams Fork		S	B		X	X				2	
	Jim Bridger	Green R.		S	S					X		2	
	Rainbow #8	Green R.		U	B						X	1	14
												TOTAL	39

State	Mine	Water Source				Direct Retort	Indirect Retort			Plant-Site Combinations	
		Surface	Ground	Mining[a]	Shale[c]	Paraho Direct	Paraho Indirect	TOSCO II		No.	Total State
Colorado	Parachute Creek	Colorado R.		U	HG	X	X	X		3	3
										TOTAL	3

[a] U = Underground; S = Surface
[b] B = Bituminous; L = Lignite; S = Subbituminous
[c] HG = High grade shale

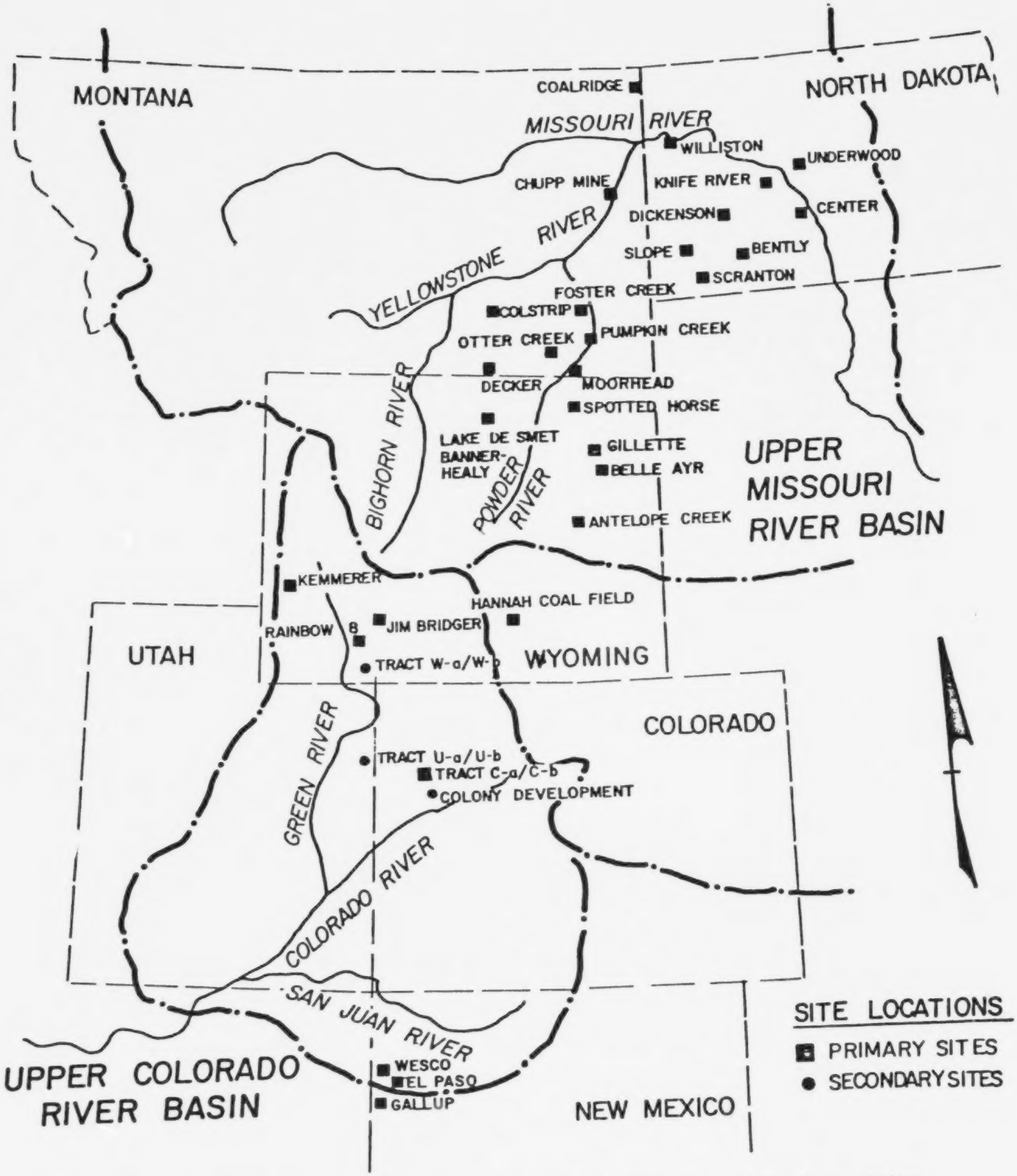
MONTANA
NORTH DAKOTA
COALRIDGE
MISSOURI RIVER
WILLISTON
UNDERWOOD
KNIFE RIVER
CHUPP MINE
CENTER
DICKENSON
YELLOWSTONE RIVER
SLOPE
BENTLY
SCRANTON
FOSTER CREEK
COLSTRIP
PUMPKIN CREEK
OTTER CREEK
DECKER
MOORHEAD
SPOTTED HORSE
BIGHORN RIVER
LAKE DE SMET
BANNER-HEALY
GILLETTE
BELLE AYR
POWDER RIVER
ANTELOPE CREEK
UPPER MISSOURI RIVER BASIN
KEMMERER
HANNAH COAL FIELD
RAINBOW 8
JIM BRIDGER
UTAH
TRACT W-a/W-b
WYOMING
COLORADO
GREEN RIVER
TRACT U-a/U-b
TRACT C-a/C-b
COLONY DEVELOPMENT
COLORADO RIVER
SAN JUAN RIVER
WESCO
EL PASO
GALLUP
UPPER COLORADO RIVER BASIN
NEW MEXICO
SITE LOCATIONS
■ PRIMARY SITES
● SECONDARY SITES

Figure 3-1. Coal and oil shale conversion site locations in Western states.

The synthetic fuel technologies examined include: coal gasification to convert coal to pipeline gas; coal liquefaction to convert coal to low sulfur fuel oil; coal refining to produce a de-ashed, low sulfur solvent refined (clean) coal; and oil shale retorting to produce synthetic crude. Detailed conceptual designs for integrated mine-plant complexes were made for each of the representative conversion processes in order to compare water requirements, types of water treatment plants, and the quantities of wet-solid residuals generated. The products and processes chosen for comparison are shown in Table 3-2.

The process criteria for the conversion of coal were defined based on the quality of the foul condensate recovered after gasification or liquefaction. Low temperature gasifiers (e.g. Lurgi and Synthane) using lower rank subbituminous coals produce a very dirty condensate (typical values: BOD ∿ 10,000 mg/l, phenol ∿ 3,000 mg/l and ammonia ∿ 7,000 mg/l). The high temperature gasifiers (e.g. Koppers - Totzek and Bigas) produce a relatively clean process condensate (typical values: ammonia ∿ 4,500 mg/l, BOD and phenol ∿ small), while the intermediate temperature Hygas gasifier using a higher rank bituminous coal produces a condensate of intermediate quality. Both the Synthoil and Solvent Refined Coal (SRC) processes have the foulest condensate (typical values for SRC: BOD ∿ 30,000 mg/l, phenol ∿ 5,000 mg/l and ammonia ∿ 8,000 mg/l).

For oil shale conversion, we only considered underground mining followed by surface retorting. In situ retorting processes are under development and cannot yet be considered suitable for commercial operation. Oil shale retorts are classified into two basic types, those that are direct heated, such as the Paraho Direct process, and those that are indirect heated, such as the TOSCO II and Paraho Indirect processes. From the point of view of water management, the type of retort is quite important. When the retort is direct heated, most of the water is recovered, while with indirect heated retorts, the water in the combustion products is generally lost up a furnace stack and not recovered. Furthermore, for direct heated processes, no intermediate medium is used to transfer heat from the pyrolysis and the thermal efficiency is high, resulting in reduced cooling loads, as compared to the indirect heated retorts. Finally, large amounts of water are required for the disposal and revegetation of the spent shale piles and different procedures with considerably different water requirements have been proposed for the Paraho and TOSCO spent shales.

TABLE 3-2 PRODUCT FUEL OUTPUT OF STANDARD SIZE SYNTHETIC FUEL PLANTS

Technology and Conversion Process	Product	Output	Product Heating Value (10^{11} Btu/day)
Coal Gasification	Pipeline Gas	250x10^6 scf/day	2.4
Lurgi* Synthane* Hygas Bigas			
Coal Liquefaction	Fuel Oil	50,000 barrels/day	3.1
Synthoil*			
Coal Refining	Solvent Refined Coal	10,000 tons/day	3.2
SRC			
Oil Shale	Synthetic Crude	50,000 barrels/day	2.9 (2.8)+
Paraho Direct Paraho Indirect TOSCO II*			

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*Processes studied in Reference 1 for the Technology Assessment of Western Energy Resource Development study.

+Value used in Reference 1.

Site selection was based on the availability of coal and oil shale, the type of coal (bituminous, subbituminous or lignite) or oil shale (high grade or low grade), the type of mining (underground or surface) and the availability of surface and ground water.

In the West, lignite is found in North Dakota and eastern Montana, while subbituminous coal is found in southeastern Montana, Wyoming, and New Mexico. Some bituminous coal is found in southern Wyoming. Sites were selected based on the coal reserves required for a standard size conversion plant operating at 90 percent production capacity over a thirty-year period. For a Synthane plant a total recoverable reserve of approximately 200 x 10^6 tons of lignite are required. The recoverable reserve is the amount of coal actually mined or recovered as distinguished from the amount of coal present in the ground, or coal reserve. The total recoverable coal reserve is about 50 percent of the total coal reserve for underground mining and about 80 percent for surface mining. The sites were chosen in those coal regions where the largest and most easily mined deposits are located. These are the Powder River and Fort Union coal regions in Montana, Wyoming and North Dakota, and the Four Corners coal region in New Mexico. A total of 28 coal conversion sites were selected; 9 in Wyoming, 8 each in Montana and North Dakota, and 3 in New Mexico.

Depending on the shale grade and the particular process, approximately 75,000 to 100,000 tons of high grade shale must be mined daily from an underground shale mine integrated with a shale oil plant to produce 60,000 to 75,000 barrels/day of shale oil. This is the range of shale oil needed to produce 50,000 barrels/day of synthetic crude in a self-sufficient integrated plant. For one plant a total recoverable reserve of from 600 x 10^6 to 730 x 10^6 barrels of shale oil are needed, assuming a 90 percent load factor and a 30 year mine life. If 30 percent of the shale remains underground with conventional room-and-pillar mining techniques, then a total reserve in the range of 860 x 10^6 and 1,040 x 10^6 barrels of shale oil is required for a plant producing 50,000 barrels/day of synthetic crude. The only oil shale considered was high grade shale from the Green River Formation in Colorado and Utah.

3.3 WATER SUPPLY AND DEMAND

Potential water supply sources for each site were evaluated on a site specific base in terms of total available water supply, required plant use, needs and rights of other competing water users, and the quality of the alternative water supplies. Factors considered were the extent and variability of nearby stream flows or groundwater aquifers, legal institutions regulating the use of these waters and the implications of competing users for limited supplies in certain areas. The water sources listed in Table 3-1 are assumed to be the nearest reliable water sources of sufficient size for which there was water quality data available.

The water resources in the major coal and oil shale bearing regions of the Western United States were conveniently separated into two major water shed regions: the Upper Missouri River Basin and the Upper Colorado River Basin. Each one of the Basins was further divided into several hydrologic subregions and estimates made of water availability within each subregion for coal and oil shale production.

In the Powder River and Ft. Union coal regions shortages occur in parts of the Yellowstone River Basin during periods of low flow. Water can be obtained by appropriation and transferred by transbasin diversions. However, there are a number of serious institutional conflicts in the region, particularly in Montana and Wyoming, concerning the authority to allocate water. Competitive pressures from agricultural water users are very high and irrigation needs are large because of the semi-arid climate. Environmental problems associated with the disruption of natural underground reservoirs by mining may also be important.

The coal and oil shale regions of the Upper Colorado River Basin are situated in an arid area marked by an inadequate water supply of poor quality. The region is subjected to highly variable annual stream flows. It may be possible to utilize groundwater as a conjunctive supply, but this water is generally of a poor quality and often drawn from underground reservoirs which would eventually be depleted. However, we should note that for some proposed oil shale developments, the quantity of groundwater produced by mine dewatering would exceed the plant water requirements. Strong competition exists among agricultural, municipal and industrial users for the available supply, most of which is now either appropriated or over-appropriated. Serious institutional conflicts involving Indian water rights also exist in the area.

Because agriculture has long been an important part of the Western economy, numerous storage reservoirs have been built throughout both Basins to more evenly distribute spring runoff during the year, particularly the growing season.

Two limiting cases were examined with respect to water availability in the West: low water demand and high water demand. Low water demand corresponds to a synthetic fuel production rate of approximately 1.0 x 10^6 barrels/day of synthetic crude, or its equivalent of 5.8 x 10^{12} Btu/day, while high water demand corresponds to a synthetic fuel production rate of 4.0 x 10^6 barrels/day of synthetic crude, or its equivalent in other fuels of 23.2 x 10^{12} Btu/day. For low water demand, two standard size coal or oil shale conversion plants (without regard to type) were assumed to be located in each of eleven hydrologic subregions for a total of 22 plants. This corresponds to the production of approximately 1.0 x 10^6 barrels/day of synthetic crude. For high water demand, 1 x 10^6 barrels/day of synthetic crude, or its equivalent in other fuels, were produced in each of the three principal coal bearing regions (Ft. Union, Powder River and Four Corners) and in the principal oil shale region (Green River Formation), for a total production of 4 x 10^6 barrels/day.

Low water demand can be accommodated by available supplies in most of the subregions. However, chronic water shortages do exist, especially in the northern Wyoming area of the Powder River coal region and the Tongue-Rosebud drainage area in the Ft. Union coal region. In the Four Corners-San Juan region in northwestern New Mexico and the Belle-Fourche-Cheyenne basin in northeast Wyoming, the water demands are greater than about twenty percent of the total water availability, which may be considered to be excessive. For high water demand, projected loads cannot be accommodated by available supplies in most subregions. Only in the Yellowstone, Upper Missouri, Lower Green and Upper Colorado mainstem basins does it appear that sufficient supplies are available for the expected loads of energy production. However, water availability in the Upper Colorado River Basin may be limited because all of the water rights to most of the free flowing water in the Basin are already allocated. These rights would have to be transferred to support additional energy development or water transferred by transbasin diversion.

The cost of water and its availability determines the degree to which wet cooling should be used. At a site where water is plentiful and inexpensive to transport, high wet cooling should be used. In regions where water is marginally available or moderately expensive to transport, an intermediate degree of wet cooling should be used, and where water is expensive to transport or scarce, minimum practical wet cooling should be used.

The results presented in Section 2 suggest that the three cooling options could be denoted by the different degrees of wet cooling used for turbine condensers and gas-compressor interstage coolers. High wet cooling would correspond to the case where the cooling loads on both the turbine condensers and interstage coolers are all wet cooled. Estimates for the Synthane process show that wet cooling is used to dispose of from 30 to 33 percent of the total unrecovered heat for high wet cooling. High wet cooling would be used when water costs less than $0.25/1000 gals.

Intermediate wet cooling assumes that wet cooling handles 10 percent of the cooling load on the turbine condensers and all of the load of the interstage coolers. Approximately 15 to 18 percent of the unrecovered heat is dissipated by wet cooling in the Synthane process. Intermediate wet cooling would be used when water costs in the range $0.25/1000 gals and $1.50/1000 gals.

Minimum practical wet cooling assumes that wet cooling handles 10 percent of the cooling load on the turbine condensers and 50 percent of the load on the interstage coolers. Approximately 12 to 16 percent of the total unrecovered heat is dissipated by wet cooling in the Synthane process under these conditions. Minimum cooling is used when the cost of water exceeds $1.50/1000 gals.

Estimates have been made of the cost of transporting water to the point of use. Figure 3-2 shows the cost of transporting water to all sites for low water demand. We assumed that a single pipeline supplies water to a single plant. Except for plants located near the mainstem of major rivers or near large reservoirs, Figure 3-2 shows that intermediate or minimum practical wet cooling is desirable for most of the sites in the West.

For large scale synthetic fuel production, it is more economical to have a large pipeline built to transport water to a large number of plants than to have a large number of individual pipelines supplying individual plants. Figure 3-3 shows for high water demand the cost of transporting large quantities of water to some of the major coal producing areas and indicates that except for large scale development near the mainstem of major rivers, intermediate cooling is desirable for most of the study region.

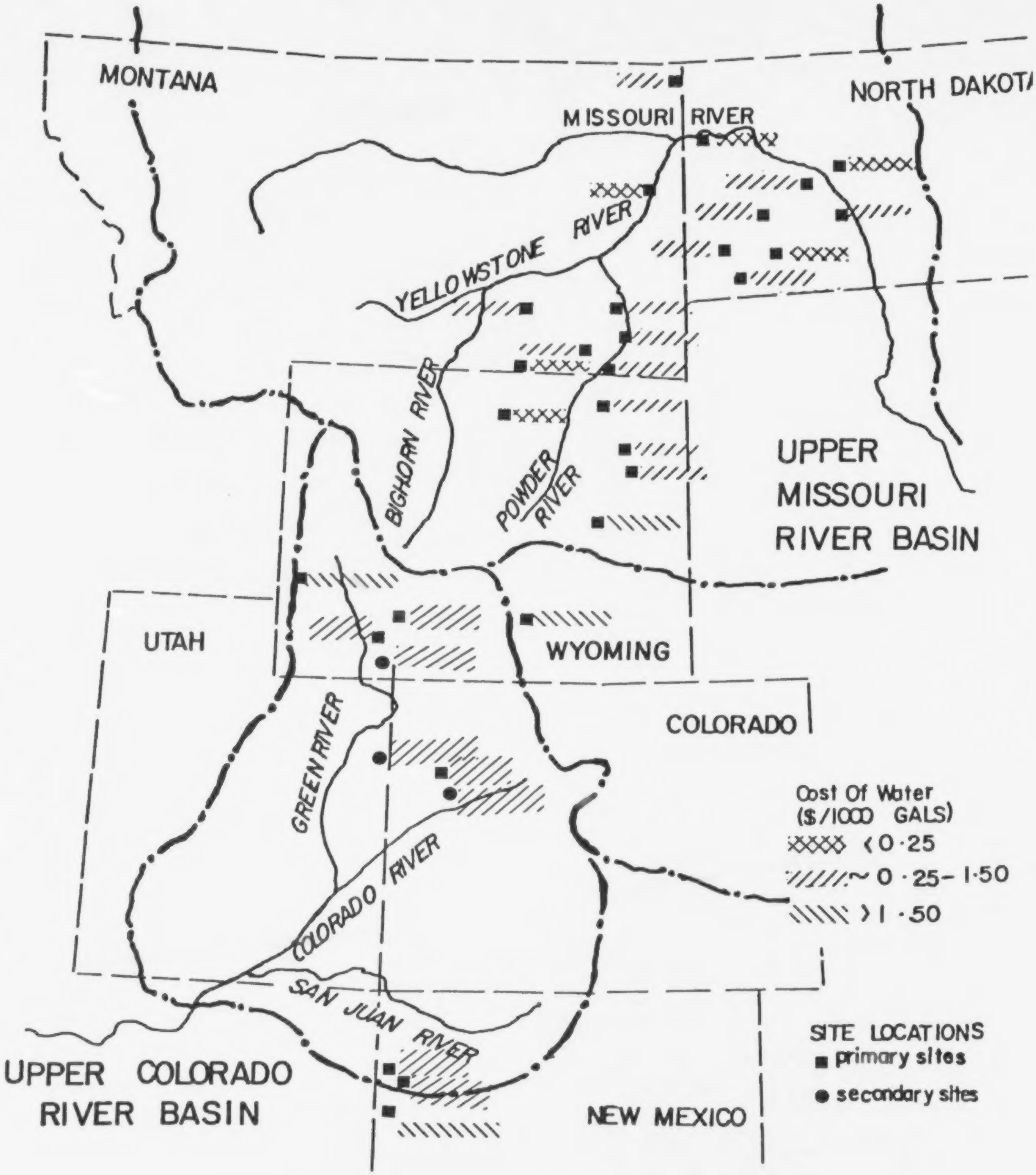
MONTANA
NORTH DAKOTA
MISSOURI RIVER
YELLOWSTONE RIVER
BIGHORN RIVER
POWDER RIVER
UPPER MISSOURI RIVER BASIN
UTAH
WYOMING
COLORADO
GREEN RIVER
COLORADO RIVER
SAN JUAN RIVER
UPPER COLORADO RIVER BASIN
NEW MEXICO
Cost Of Water ($/1000 GALS)
XXXXX < 0.25
////// ~ 0.25 - 1.50
\\\\\\ > 1.50
SITE LOCATIONS
■ primary sites
● secondary sites

Figure 3-2. Cost of transporting water to specific site locations in the Western states.

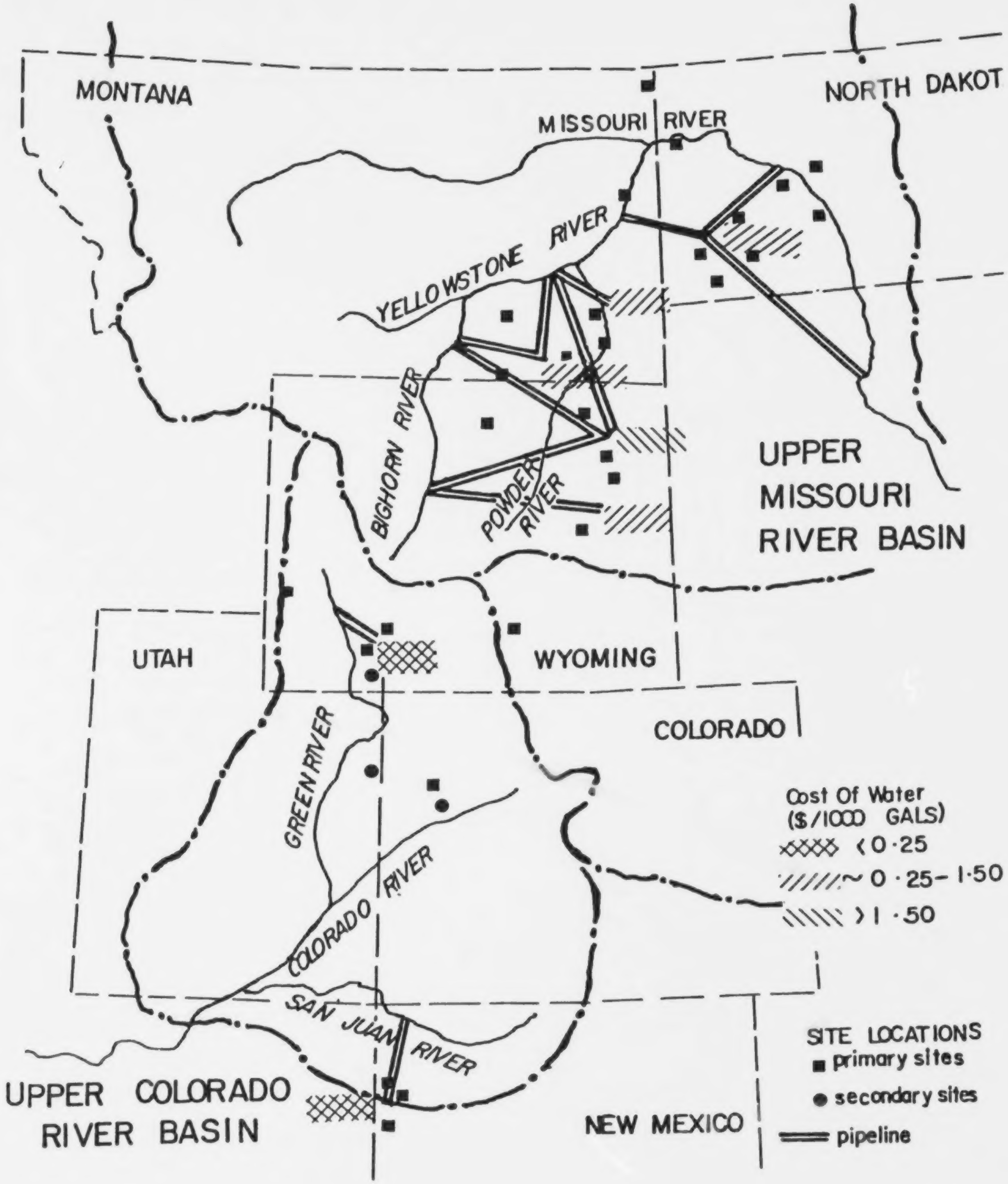
MONTANA
NORTH DAKOT
MISSOURI RIVER
YELLOWSTONE RIVER
BIGHORN RIVER
POWDER RIVER
UPPER MISSOURI RIVER BASIN
UTAH
WYOMING
COLORADO
GREEN RIVER
COLORADO RIVER
SAN JUAN RIVER
UPPER COLORADO RIVER BASIN
NEW MEXICO
Cost Of Water ($/1000 GALS)
< 0·25
~ 0·25- 1·50
> 1·50
SITE LOCATIONS
primary sites
secondary sites
pipeline

Figure 3-3. Cost of transporting water to coal regions in the Western states.

3.4 TOTAL WATER CONSUMED AND RESIDUALS GENERATED

Water consumption is based on net water consumption. All effluent streams are assumed to be recycled or reused within the mine or plant after any necessary treatment. These streams include the organically contaminated process condensate waters and the highly saline water blown down from the cooling system. Water is released to evaporation ponds as a method of salt disposal. However, we have generally assumed that the highly saline waters can be disposed of with the coal ash. We have not considered the recovery of water from the drying of high moisture content coal such as lignite, because the costs are high, in the range of \$1.30 to \$1.50 per 1000 gallons[3]. However, recovery is a serious possibility when water is particularly scarce, especially in the West. The rest of the water leaves the plant as vapor, as hydrogen in the hydrocarbon products, or as occluded water in the solid residues. Dirty water is cleaned but only for reuse and not for returning it to a receiving water. No waters are returned to the receiving waters. The totals for wet-solid residuals include the solid residue as well as the occluded water in the solid residue.

We have found it convenient to present the results by coal and oil shale region and by coal rank within each region, in contrast to a breakdown by state, as was done in Table 3-1. Table 3-3 shows the sites located within each major coal and oil shale bearing region, together with the coal rank and shale grade.

Mining Rates

The daily coal and oil shale mining rates for standard size synthetic fuel plants operating at a capacity of 90 percent are shown in Table 3-4. For a limited number of process-region-coal rank combinations not covered in Reference 2, the results of Reference 4 have been used. The results of Reference 2 are compared to those of Reference 1 (Technology Assessment). Most of the differences can be attributed to some minor differences in the way the calculations were carried out. For the Synthoil plant at Four Corners, the large difference is due mainly to the different coals used. The daily mining rates per unit of heating value in the product fuel are shown in Table 3-5.

Total Net Water Consumed

Tables 3-6 and 3-7 summarize the total net water consumed for the three different cooling options described in Section 3.3. The range in the total water consumed reflects the variation with site. The results of Reference 1 (Technology Assessment) and Section 1 of this report are compared to those of Reference 2.

TABLE 3-3 STUDY SITES COMPRISING COAL AND OIL SHALE BEARING REGIONS

	Coal Conversion	
Coal Region	Coal Rank	Site
Four Corners	Subbituminous	New Mexico (all sites)
Powder River and Fort Union Basins	Lignite	U.S. Steel Chupp Mine, Montana Coalridge, Montana East Moorhead, Montana Otter Creek, Montana Pumpkin Creek, Montana North Dakota (all sites)
	Subbituminous-Bituminous	Colstrip, Montana Decker, Montana Foster Creek, Montana Wyoming (all sites)

	Oil Shale Conversion	
Oil Shale Region	Shale	Site
Green River Formation	High Grade	Parachute Creek, Colorado

TABLE 3-4 SUMMARY OF COAL AND OIL SHALE MINING RATES IN 1000 TONS PER CALENDAR DAY FOR STANDARD SIZE SYNTHETIC FUEL PLANTS OPERATING AT 90 PERCENT CAPACITY

	Powder R/Ft. Union Basin		Four Corners	Green River Formation
	Subbituminous -Bituminous	Lignite	Subbituminous	Oil Shale
Coal Gasification				
Lurgi	15.0-23.6 (24.7-25.1)+	26.7-31.6 (31.1)	17.5-23.4 (25.6)	-
Synthane	19.9-21.3 (22.2-22.6)	27.5* (28.0)	23.3* (23.0)	-
Hygas	13.9-19.3	22.0	13.1-17.4	-
Bigas	11.8	23.7-28.9	-	-
Coal Liquefaction				
Synthoil	22.2-23.1 (21.9)	28.4* (27.6)	17.0 (22.7)	-
Coal Refining				
SRC	17.9-26.0	25.4-38.5	25.5*	-
Oil Shale				
Paraho Direct	-	-	-	83
Paraho Indirect	-	-	-	95
TOSCO II	-	-	-	66 (60)

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*From data in Ref. 4

+Numbers in parentheses are from Ref. 1 (Technology Assessment of Western Energy Resource Development study).

TABLE 3-5 SUMMARY OF COAL AND OIL SHALE MINING RATES

NORMALIZED WITH RESPECT TO THE HEATING VALUE IN THE PRODUCT FUEL IN 100 LBS/10^6 BTU

	Powder R/Ft. Union Basin		Four Corners	Green River Formation
	Subbituminous -Bituminous	Lignite	Subbituminous	Oil Shale
Coal Gasification				
Lurgi	1.4-2.2 (2.3)[+]	2.5-2.9 (2.9)	1.6-2.2 (2.4)	-
Synthane	1.8-2.0 (2.1)	2.5* (2.6)	2.2* (2.1)	-
Hygas	1.3-1.8	2.0	1.2-1.6	-
Bigas	1.1	2.2-2.7	-	-
Coal Liquefaction				
Synthoil	1.6-1.7 (1.6)	2.0* (2.0)	1.2 (1.6)	-
Coal Refining				
SRC	1.2-1.8	1.8-2.7	1.8*	-
Oil Shale				
Paraho Direct	-	-	-	6.3
Paraho Indirect	-	-	-	7.2
TOSCO II	-	-	-	5.0 (4.7)

---

*From data in Ref. 4

[+] Numbers in parentheses are from Ref. 1 (Technology Assessment of Western Energy Resource Development Study).

TABLE 3-6. SUMMARY OF NET WATER CONSUMED IN 10^6 GPD FOR STANDARD SIZE SYNTHETIC FUEL PLANTS OPERATING AT 90 PERCENT CAPACITY

	Powder River/Ft. Union Regions						Four Corners			Green River Formation
	Subbituminous-Bituminous			Lignite			Subbituminous			Oil Shale
	1	2	3	1	2	3	1	2	3	2
Coal Gasification										
Lurgi	5.0-6.2(5.3-5.6)+	3.3-4.6(3.8-4.1)	3.0-4.3(3.3-3.7)	4.8-5.1(4.4)	3.0-3.2(3.0)	2.6-2.9(2.5)	6.3-6.5 (6.4)	4.6-4.8 (5.0)	4.2-4.4 (4.7)	-
Synthane	5.4-5.8(6.9-7.0)	3.7-4.0(5.2-5.3)	3.3-3.7(4.9-5.0)	5.1* (6.8)	3.2* (5.2)	2.8 (4.9)	5.9* (7.7)	3.7* (6.0)	3.4* (5.6)	-
Hygas	4.4-4.9	3.3-3.8	3.2-3.6	4.5	3.4	3.2	4.9-5.0	3.8-3.9	3.6-3.7	-
Bigas	5.3	3.3	3.1	5.7-5.9	3.8-3.9	3.5-3.6	-	-	-	-
Coal Liquefaction										
Synthoil	4.7-4.8(4.1-4.6)	3.0-3.1(3.4-3.8)	2.7-2.8(3.1-3.5)	5.5* (4.5)	3.9* (3.6)	3.6* (3.4)	5.4-6.0* (5.1)	3.9-4.6* (4.3)	3.6-4.3* (4.1)	-
Coal Refining										
SRC	3.9-4.4	2.3-2.7	2.1-2.3	4.4-5.9	2.6-3.3	2.3-2.8	4.3*	3.1*	3.0*	-
Oil Shale										
Paraho Direct							-	-	-	4.6 (4.6)
Paraho Ind.							-	-	-	7.4 (7.4)
TOSCO II							-	-	-	7.5 (7.5)**

---

1 = High Wet Cooling, 2 = Intermediate Wet Cooling, 3 = Minimum Practical Wet Cooling

*Data from Ref. 4, only applies to particular number and not range.

+Numbers in parentheses are from Ref. 1 (Technology Assessment of Western Energy Resource Development Study)

**Modified from calculations presented in Ref. 1.

TABLE 3-7. SUMMARY OF NET WATER CONSUMED NORMALIZED WITH RESPECT TO THE HEATING VALUE IN THE PRODUCT FUEL IN GAL/10^6 BTU

	Powder River/Ft. Union Regions						Four Corners			Green River Formation
	Subbituminous-Bituminous			Lignite			Subbituminous			Oil Shale
	1	2	3	1	2	3	1	2	3	2
Coal Gasification										
Lurgi	23-29 (24-26)+	15-21 (17-19)	14-20 (15-17)	22-24 (20)	14-15 (14)	12-13 (12)	29-30 (29)	21-22 (23)	20-21 (22)	-
Synthane	25-27 (32)	17-19 (24)	16-17 (23)	24* (32)	15* (24)	13* (23)	28* (36)	18* (28)	16* (26)	-
Hygas	21-23	16-18	15-17	21	16	15	23	18	17	-
Bigas	24	16	14	26-27	18	16-17	-	-	-	-
Coal Liquefaction										
Synthoil	17 (15-17)	11 (12-14)	10 (11-13)	19* (16)	14*(13)	13* (12)	20-22* (18)	14-16* (15)	13-16* (14)	-
Coal Refining										
SRC	13-15	8-9	7-8	15-21	8-9	7-8	15*	11*	10*	-
Oil Shale										
Paraho Direct							-	-	-	18 (18)
Paraho Ind.							-	-	-	28 (28)
TOSCO II							-	-	-	29 (29)**

---

1 = High Wet Cooling, 2 = Intermediate Wet Cooling, 3 = Minimum Practical Wet Cooling

*Data from Ref. 4, only applies to particular number and not range.

+Numbers in parentheses are from Ref. 1 (Technology Assessment of Western Energy Resource Development Study.

**Modified from calculations presented in Ref. 1.

Except for the Synthane process the results of the limited six site-specific studies are in general agreement with the results of the expanded site studies. As was mentioned previously, small differences are attributed to differences in the way the calculations were carried out. For Synthane, the major difference is in the degree to which wet cooling was used to dissipate the unrecovered heat. In Ref. 1 (p. 53) approximately 2.7×10^9 Btu/stream hr was dissipated by wet cooling. However, in Ref. 2, a more detailed thermal balance was made and only about 1.85×10^9 Btu/stream hr was dissipated by wet cooling at some of the Western sites. This difference results in a difference in the net water consumed of 1.5×10^6 gal/cal. day, or about 7 gals/10^6 Btu. These differences are shown in Tables 3-6 and 3-7.

Figures 3-4 and 3-5, taken from Ref. 2, show a breakdown of the average net water consumption by region and by process and for the three cooling options. Four water use categories are presented for each coal conversion process in each region: net process water based on reuse of all condensate; cooling water, flue gas desulfurization water, if necessary; and water for mining, dust control, solids disposal, water treatment, revegetation and other uses. For oil shale it is most convenient to break down the water use categories in a slightly different way to reflect the large quantities of water required for spent shale disposal: net process water for retorting and upgrading; cooling water; water for spent shale disposal and revegetation; and water for dust control, mining and other uses. For the cases where the net process water is negative (i.e., net water produced in the process), the cooling water requirements can be obtained by adding the absolute value of the process water to the cooling water component.

Except for the Hygas process, the net water consumed for the Four Corners region is higher than for the other regions because of the larger amount of water needed for dust control and the handling of ash for the high ash Navajo, New Mexico coal. Water is required for revegetation in New Mexico because the rainfall is less than 10 inches per year, but is not required at any other location. For the Hygas process there are many other competing demands which make the above generalization invalid.

It should be noted that within a given coal region and for a given process, rank of coal, and wet cooling option, differences in the net water consumed from site to site are not significant. However, within a given region there might be large variations in water availability and water costs and different cooling options at different sites will produce large differences in the cooling water

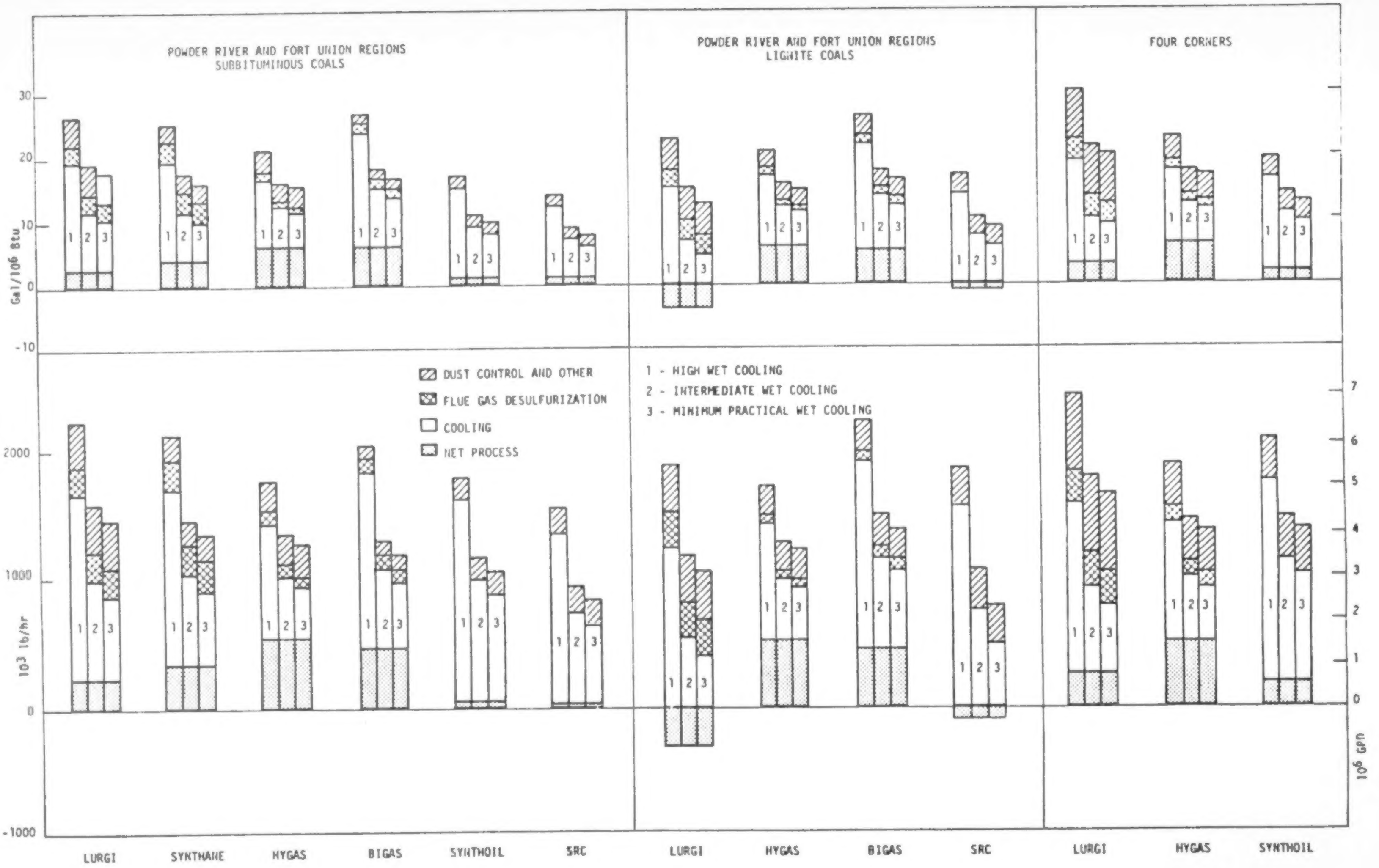

Figure 3-4. Summary of average net water consumed for coal conversion plants located in the Western states.

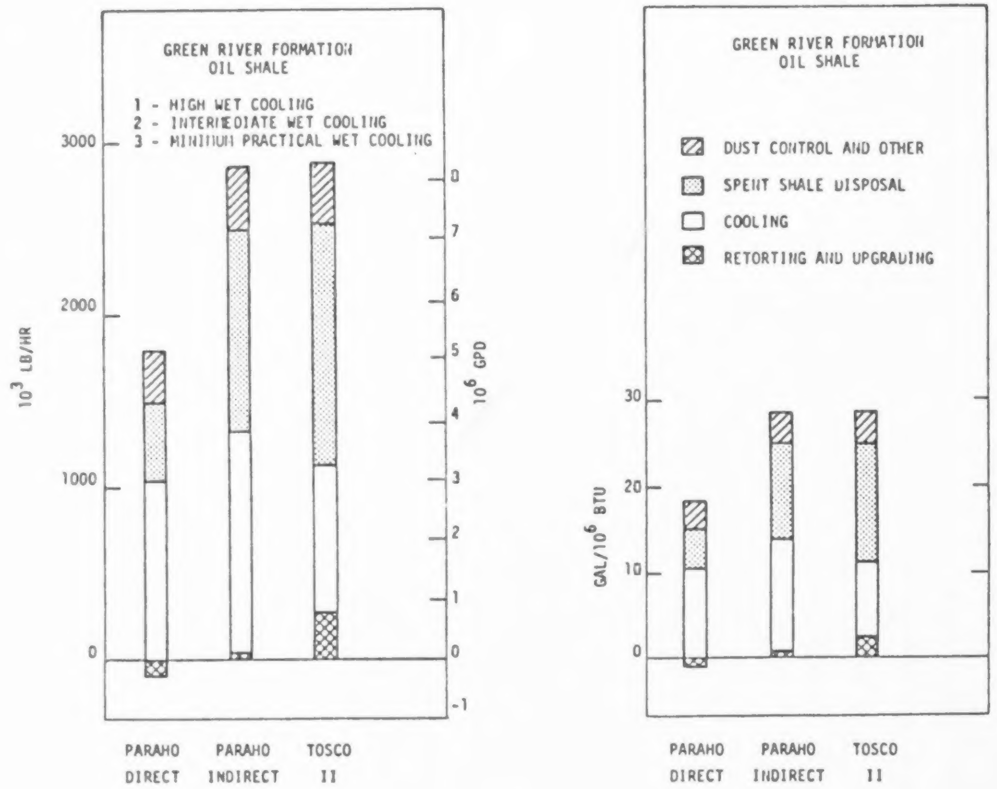

Figure 3-5 Summary of net water consumed for oil shale conversion plants located in the Western states

consumed and the plant water requirements. Thus, for a particular process and coal rank, the cost of water and the particular cooling technology selected for a given plant are the main factors which determine the water use. As we pointed out in Section 3.2, intermediate and minimum practical wet cooling should be used at most of the sites.

Total Wet-Solid Residuals Generated

Solid residuals generated in coal and oil shale conversion plants are generally disposed of wet with occluded water. Tables 3-8 and 3-9 summarize the total wet solid residuals by coal region and rank and oil shale region and grade. Figures 3-6 and 3-7, taken from Ref. 2, show a breakdown of the average wet solid residuals by region and by process. Three categories are presented for each conversion process: ash sludge, flue gas desulfurization sludge and water treatment sludge. Flue gas scrubbing is not required for the Synthoil and SRC processes. Only the category of wet spent shale is shown for oil shale conversion.

The results of Ref. 1 (Technology Assessment) are compared to those of Ref. 2 in Tables 3-8 and 3-9. The total wet solid residuals generated for the expanded site study are about twice those of the Technology Assessment study for coal conversion due primarily to the much larger quantities of flue gas desulfurization sludge and water treatment sludge generated.

In general coal gasification generates the largest quantity of wet residuals normalized with respect to the product heating value, followed in turn by coal liquefaction and coal refining. For the same process, there are no significant variations with coal rank in the Powder River and Fort Union coal regions except for the Bigas process; for Bigas the variation is due to the higher ash coals. The larger quantities of wet solids generated in the Four Corners region are due to the high ash content of the Navajo coal.

REFERENCES (Section 3)

1. Gold, H., et al, "Water Requirements for Steam-Electric Power Generation and Synthetic Fuel Plants in the Western United States," EPA Report No. 600/7-777-037, U.S. Environmental Protection Agency, Washington, D.C., April 1977.

2. Gold, H. and Goldstein, D.J., "Water Related Environmental Effects in Fuel Conversion," EPA Report 600/7-78-197a, b, U.S. Environmental Protection Agency, Research Triangle Park, N.C., October, 1978.

3. Goldstein, D.J. and Yung, D., "Water Conservation and Pollution Control in Coal Conversion," EPA Report 600/7-77, EPA, Research Triangle Park, June, 1977.

4. Probstein, R.F. and Gold, H., Water in Synthetic Fuel Production - The Technology and Alternatives, MIT Press, Cambridge, Mass., 1978.

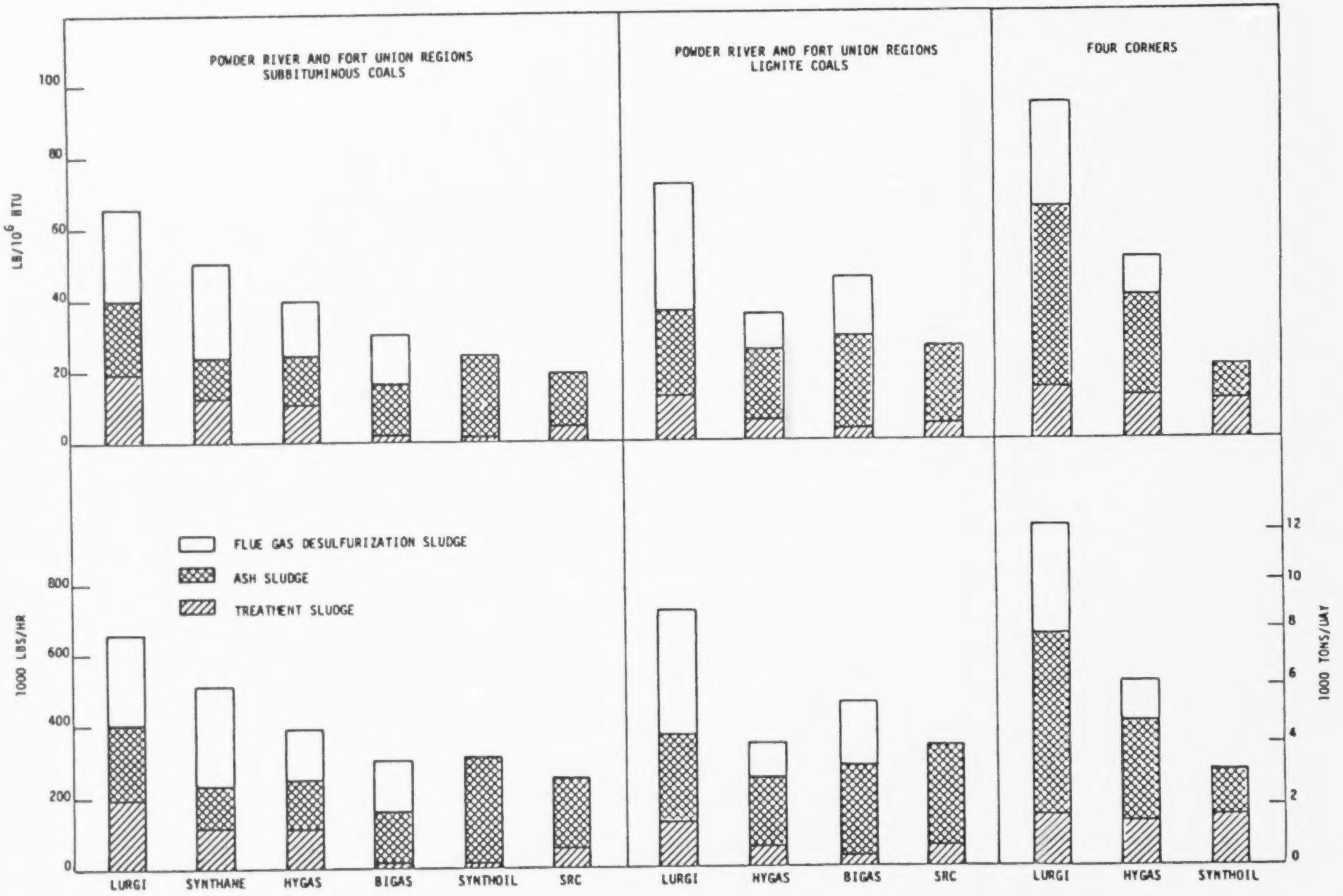

Figure 3-6 Summary of average wet-solid residuals generated from standard size coal conversion plants located in the Western states

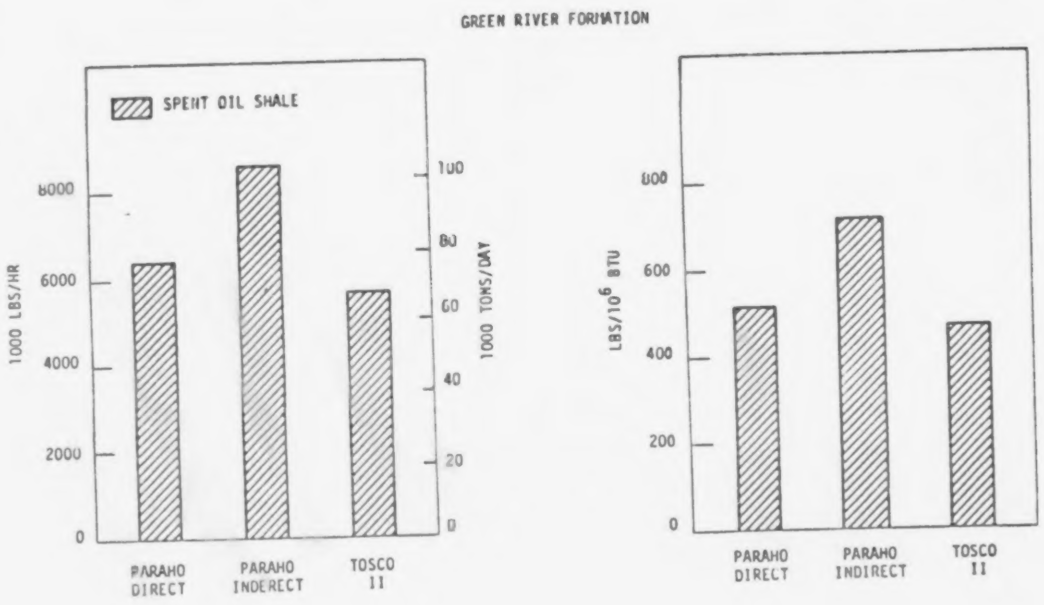

Figure 3-7 Summary of average wet solid residuals generated from standard size oil shale plants located in the Western states.

TABLE 3-8 SUMMARY OF TOTAL WET RESIDUALS GENERATED
IN 10^3 TONS/DAY FOR STANDARD SIZE SYNTHETIC FUEL PLANTS OPERATING AT 90 PERCENT CAPACITY

	Powder R/Ft. Union Basin		Four Corners	Green River Formation
	Subbituminous -Bituminous	Lignite	Subbituminous	Oil Shale
Coal Gasification				
Lurgi	6.8-7.7 (2.0-3.5)+	6.6-9.0 (3.3)	6.4-13.6 (8.2)	-
Synthane	5.0-6.0 (1.9-3.1)	3.5* (3.0)	6.3* (7.8)	-
Hygas	3.4-5.0	3.8	4.2-6.9	-
Bigas	3.2	3.7-7.5	-	-
Coal Liquefaction				
Synthoil	3.0-3.6 (1.7-2.8)	4.8* (2.8)	2.9-10.1* (7.3)	-
Coal Refining				
SRC	1.8-3.4	2.9-4.2	12.3*	-
Oil Shale				
Paraho Direct	-	-	-	68
Paraho Indirect	-	-	-	94
TOSCO II	-	-	-	61 (56)

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*From data in Ref. 4

+Numbers in parentheses are from Ref. 1 (Technology Assessment of Western Energy Resource Development Study).

TABLE 3-9 SUMMARY OF TOTAL WET RESIDUALS GENERATED NORMALIZED WITH RESPECT TO THE HEATING VALUE IN THE PRODUCT FUEL IN LBS/10^6 BTU

	Powder R/Ft. Union Basin		Four Corners	Green River Formation
	Subbituminous -Bituminous	Lignite	Subbituminous	Oil Shale
Coal Gasification				
Lurgi	61-68 (18-32)	61-83 (31)	59-126 (76)	-
Synthane	46-56 (18-28)	33* (27)	59* (72)	-
Hygas	32-46	35	39-64	-
Bigas	30	34-69	-	-
Coal Liquefaction				
Synthoil	21-26 (12-20)	34* (20)	28-72* (52)	-
Coal Refining				
SRC	12-24	20-34	19-86*	-
Oil Shale				
Paraho Direct	-	-	-	520
Paraho Indirect	-	-	-	630
TOSCO II	-	-	-	470 (440)

---

*From data in Ref. 4

+Numbers in parentheses are from Ref. 1 (Technology Assessment of Western Energy Resource Development Study).

4. ECONOMICS OF WATER TREATMENT AND COOLING TOWER BLOWDOWN TREATMENT AND DISPOSAL

4.1 INTRODUCTION

The estimates of the quantities of net water consumed and wet solid residuals generated calculated earlier[1] are based on the assumption that no water streams leave the mine-plant boundaries and that all effluent streams are recycled or reused within the mine or plant after any necessary treatment. These streams include the organically contaminated waters generated in the conversion process, which are unfit for disposal without treatment, and the highly saline water blown down from evaporative cooling systems or produced during regeneration of the ion exchange units required to treat the source water to boiler feed water quality. The process waters are treated for use as makeup to the cooling towers while we have generally assumed that the highly saline wastes are disposed of with the coal ash, or used for flue gas desulfurization. If the saline wastes cannot be disposed of with the coal ash, it can be released to evaporation ponds as a method of salt disposal. However, the saline wastes must be highly concentrated before disposal to evaporation ponds to reduce the evaporation loss. The rest of the water leaves the plant as vapor, as bonded hydrogen (after hydrogenation) in the hydrocarbon product, and as occluded water in the solid residues. The plants are designed not to be wasteful of water by utilizing a relatively high degree of water reuse and conservation. However, they are not designed for minimum water consumption, nor are they designed to return wastewater to the source water. Returning water to a source is not economic when the water must be cleaned to a quality equal to or better than the source water to meet environmental regulations.

All wet solid residuals must be disposed of in an environmentally acceptable manner. Toxic and soluble organic materials must be destroyed and toxic heavy metal salts must be converted to insoluble forms. Soluble inorganic sludges and toxic residuals from the coal ash must be contained in disposal sites to prevent leaching into drinking water sources.

In this section we will estimate the costs of treating water in a coal gasification plant for the purpose of recycling and reusing the water for in-plant uses to minimize the problem of disposal of contaminated waste streams. In addition we will estimate the costs of the treatment and disposal of cooling tower blowdown for the two cases of zero discharge and effluent discharge to the receiving water. We did not consider the cost of disposal of all of the wet-solid streams, nor did we consider the treatment to remove trace contaminants since it was beyond the scope of this program.

The cost and energy estimates for water treatment and blowdown disposal are much less well defined than the water quantities. Although the water treatment technologies considered are achievable, experimental evidence for coal conversion process waters is not available to fully assess them. For this reason designs and costs must be regarded with a greater degree of uncertainty than the estimates of water quantity requirements. In addition we have only used one or two water flow diagrams for treating the waters in gasification plants, each applicable to one or more process at many sites. We have only considered a limited number of blowdown treatment and disposal procedures to arrive at a range of costs.

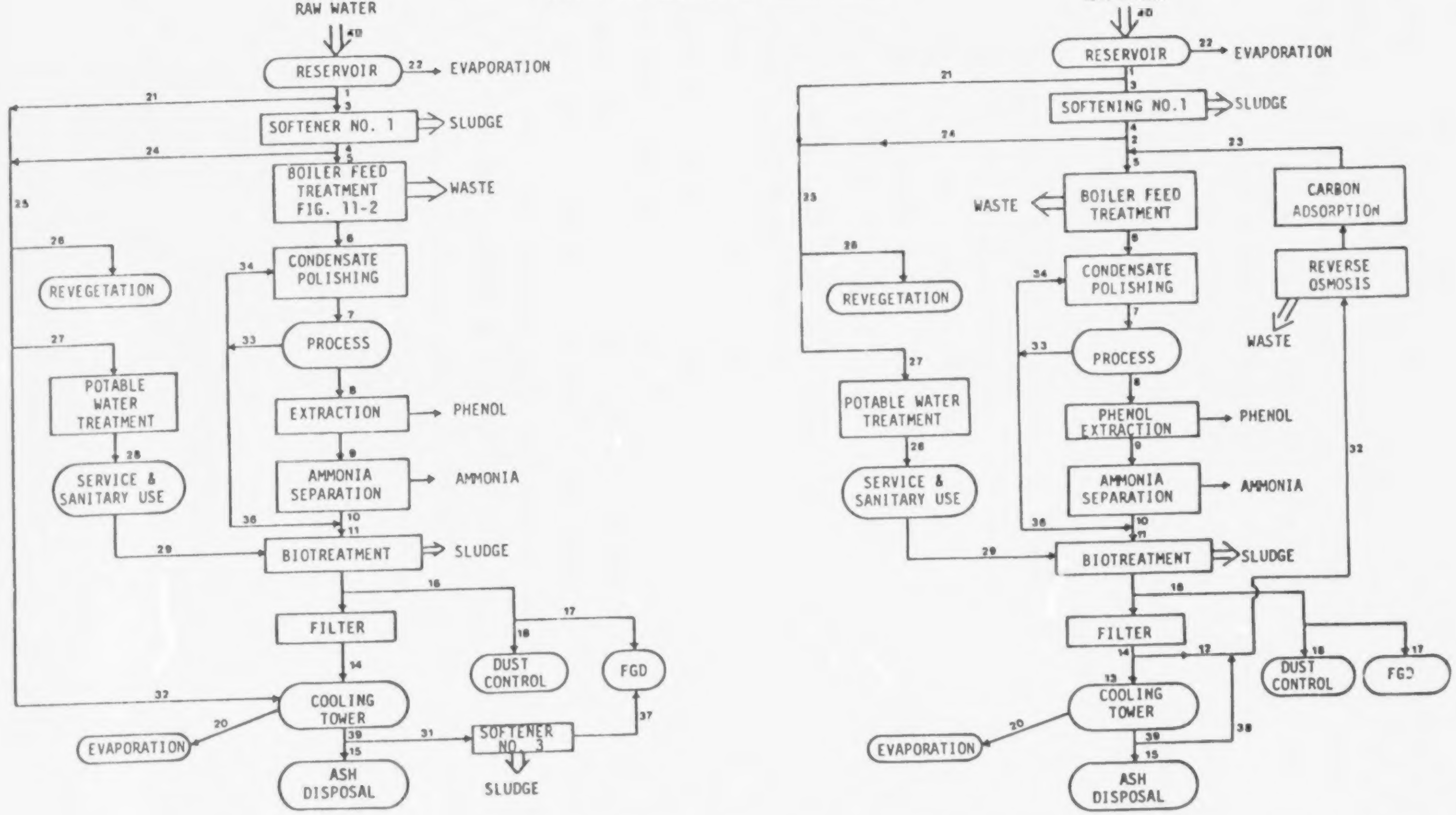
4.2 PROCESS AND COOLING WATER TREATMENT

In any synthetic fuel plant high quality water is required for the process as boiler feed water, intermediate quality is required for cooling and low quality for mine uses. Central to any water reuse scheme in a coal gasification plant is the disposition of the wastewater out of the process which is so contaminated that its release to the environment in any form is unacceptable. The water contains the products of coal reaction, coal decomposition, coal pyrolysis and varying amounts of soluble inorganic products from coal ash and gangue. The quality of this foul condensate wastewater depends on the coal and the conversion process, particularly on the gasifier temperature, and to a lesser extent on the reactor residence time and configuration. A summary of the qualities of foul condensate wastewaters for coal conversion processes is given in Reference 2. If chemical oxygen demand, COD, is taken as the primary measure of the pollutant level, the dirtiest water is from the lowest temperature processes such as Synthane and Lurgi, using the lower rank lignite and subbituminous coals. The range of COD is from about 17,000 to 43,000 mg/l[2]. Intermediate quality water with a COD ∿ 3,000[2] is obtained from higher temperature processes, such as Hygas, with the higher rank bituminous coals. Entrained flow gasifiers, such as Koppers and Bigas, are very hot and the condensate is not organically contaminated to any important extent (COD <100)[2].

The condensate wastewaters contain large quantities of ammonia and carbon dioxide. In gasifying Western low sulfur coals, the wastewater will not contain much hydrogen sulfide. The condensates are also high in phenols and contain fatty acids and other compounds which are mostly biodegradable[3,4]. Large amounts of hydrogen sulfide are found in the wastewater when gasifying Eastern high sulfur coals.

The foul condensate wastewater is assumed to be treated and used as makeup to the cooling tower. Additional makeup to the cooling tower comes from the source water. The cooling tower is blown down to prevent scale formation in the cooling system. In this section the costs and energy required to treat (1) the source water to boiler water makeup quality, (2) the foul condensate wastewater for use in the cooling tower, and (3) the circulating cooling water will be estimated for the Synthane and Lurgi processes. The costs for disposing of the wastewater streams are estimated in the next section.

Figure 4-1 are water treatment block diagrams used for all of the Synthane and Lurgi plants (taken from Reference 5). The schemes are not unique, but contain the main components of any water treatment plant: boiler feed water preparation, process water or condensate cleanup, and cooling water treatment. Figure 4-1A is used when the process condensate is insufficient to meet all of the cooling needs of the plants. It was used for the Synthane plants at Beulah, North Dakota; Colstrip, Montana; Gillette, Wyoming; and Navajo/Farmington, New Mexico; and for the Lurgi plant at Colstrip and Navajo/Farmington. Figure 4-1B is used when the process condensate is sufficient to meet all of the cooling needs of the plant and was used for the Lurgi plants at Beulah and Gillette. The Lurgi process is assumed to accept wet coal, while the feed


RAW WATER
40
RESERVOIR
22
EVAPORATION
1
3
21
SOFTENER NO. 1
SLUDGE
24
4
5
BOILER FEED TREATMENT FIG. 11-2
WASTE
6
25
26
REVEGETATION
34
CONDENSATE POLISHING
7
33
PROCESS
27
POTABLE WATER TREATMENT
8
EXTRACTION
PHENOL
9
28
SERVICE & SANITARY USE
AMMONIA SEPARATION
AMMONIA
36
10
11
29
BIOTREATMENT
SLUDGE
16
FILTER
17
18
14
DUST CONTROL
FGD
32
COOLING TOWER
20
EVAPORATION
39
15
31
SOFTENER NO. 3
37
ASH DISPOSAL
SLUDGE
RAW WATER
40
RESERVOIR
22
EVAPORATION
21
1
3
SOFTENING NO.1
SLUDGE
24
4
2
23
5
BOILER FEED TREATMENT
WASTE
CARBON ADSORPTION
25
26
6
REVEGETATION
CONDENSATE POLISHING
34
REVERSE OSMOSIS
7
WASTE
33
PROCESS
27
POTABLE WATER TREATMENT
8
PHENOL EXTRACTION
PHENOL
9
32
28
SERVICE & SANITARY USE
AMMONIA SEPARATION
AMMONIA
36
10
11
29
BIOTREATMENT
SLUDGE
16
FILTER
14
12
18
17
13
DUST CONTROL
FGD
COOLING TOWER
20
EVAPORATION
39
38
15
ASH DISPOSAL

Streams are numbered for identification

A. Water treatment plant block diagram for all Synthane and some Lurgi plants.

B. Water treatment plant block diagram for some Lurgi plants.

Figure 4-1 Water treatment block diagrams.

coal for the Synthane process is dried and the water lost in evaporation. At Beulah and Gillette, because of the high moisture content of the coals, enough water is produced during Lurgi gasification to more than supply all of the cooling needs of the plant.

Table 4-1 lists the water flow quantities for each of the plant-site combinations which are derived from the results presented in Reference 1, Section 10, and Reference 5. The stream numbers correspond to those in Figure 4-1. In the analysis of Ref.1, the process stream flow rates for Synthane were assumed to be the same at all sites.

In all cases but one the cycles of concentration in the cooling tower were assumed to be equal to ten (10) as compared to the value of 51 used in Reference 1. Ten cycles of concentration is a well established value in cooling towers in the West. The flow quantities were adjusted to accomodate this change. The one exception was the Lurgi plant in New Mexico in which the cycles of concentration were reduced to 5.2 so that all of the blowdown would be used for ash disposal. In preparing the flow diagrams, small errors were found in some of the flow quantities calculated in Reference 1. In terms of the total water consumed, the error for the Lurgi plants varied between 0.8 to 2.7 percent of the results presented in Reference 1 while for the Synthane plants the variations did not exceed 0.5 percent.

The methods used to estimate cost and energy requirements for wastewater treatment are given in Reference 5 while background information is found in Reference 2. A brief description of the treatment blocks used in the water treatment plant, together with the cost and energy estimates, are given below.

Boiler Feed Water Treatment

Ion Exchange: This treatment is required for all plants. For the Synthane and Lurgi processes boiler makeup consists primarily of steam which reacts, and some excess steam which is added to the gasifier to control the temperature. All of the plants use high pressure steam to drive rotating machinery, but the condensate is returned with less than 2 percent loss. The cost of ion exchange depends on the quantity and quality of the intake water and on the pressure of the steam raised in the boiler; the higher the pressure,

TABLE 4-1 WATER FLOW QUANTITIES IN 10^3 LB/HR

	Synthane				Lurgi			
	Beulah N.D.	Colstrip Montana	Gillette Wyoming	Navajo/ Farmington New Mexico	Beulah N.D.	Colstrip Montana	Gillette Wyoming	Farmington New Mexico
Stream No.	A*	A*	A*	A*	B*	A*	B*	A*
1	2623	2660	2646	2945	1167	1567	1443	1904
2	-	-	-	-	1145	-	1420	-
3	1861	1861	1861	1861	1145	1411	1420	1461
4	1861	1861	1861	1861	1145	1411	1420	1461
5	1861	1861	1861	1861	1511	1411	1492	1461
6	1852	1852	1852	1852	1501	1403	1484	1453
7	1994	1994	1994	1994	1790	1672	1770	1732
8	1069	1069	1069	1069	1782	1313	1476	1172
9	1069	1069	1069	1069	1782	1313	1476	1172
10	1069	1069	1069	1069	1732	1313	1476	1172
11	1500	1500	1500	1500	1782	1313	1476	1172
12	-	-	-	-	372	-	5	-
13	-	-	-	-	1209	-	1296	-
14	1208	1268	1299	1141	1581	1127	1301	899
15	58	60	39	171	83	87	51	238
16	297	237	206	364	206	191	180	278
17	164	147	133	258	58	92	99	161
18	133	90	73	106	148	99	81	117
19	-	-	-	-	-	-	-	-
20	1713	1800	1814	1880	1059	1113	1136	996
21	762	799	785	1084	22	156	23	443
22	7	16	19	28	3	10	10	18
23	-	-	-	-	366	-	72	-
24	0	0	0	0	0	0	0	0
25	762	799	785	1084	22	156	23	443
26	0	0	0	65	0	0	0	65
27	22	22	23	24	22	22	23	24
28	22	22	23	24	22	22	23	24
29	5	5	5	5	5	5	5	5
30	-	-	-	-	-	-	-	-
31	132	140	163	38	-	37	-	0
32	740	777	762	995	407	134	80	354
33	573	573	573	573	289	269	286	279
34	142	142	142	142	289	269	286	279
35	-	-	-	-	-	-	-	-
36	431	431	431	431	-	-	-	-
37	132	140	163	38	-	37	-	0
38	-	-	-	-	35	-	75	-
39	190	200	202	209	118	124	126	238
40	2630	2676	2665	2973	1170	1577	1466	1922

---

*Designates block diagram used (See Figure 4-1).

the more restrictive are the feed water requirements and the higher the cost. The pressure of the Lurgi gasifier is in the range of 350-450 psig, while the Synthane gasifier has a pressure of approximately 1000 psig. The boiler feed water makeup (Stream No. 5 in Table 4-1) for the Lurgi plant ranged from about 1410 to 1510 x 10^3 lb/hr, while for Synthane the value was 1861 x 10^3 lb/hr. In Reference 1 not enough information was available to distinguish between coals fed to the Synthane process so that the flows entering and leaving the boiler and gasifier were assumed to be the same at all four sites.

The ion exchange system used to treat the river water source at all four sites consists of a weak acid resin, a strong acid resin, a degasifier, a weak base resin, a strong base resin and a mixed bed or mixture of strong acid and strong base resins. The weak acid resin removes only that part of the total positive ions equivalent to the bicarbonate alkalinity and replaces them with H^+ ions. It is particularly suitable for removing divalent ions such as Ca^{++} and Mg^{++}. Its main advantage is that it is easy to regenerate with sulfuric acid requiring about 110% of stoichiometry. The strong acid resin replaces all of the other positive ions with H^+. However, it is much less efficient than the weak acid resin and requires H_2SO_4 regenerant usage of about 200% stoichiometry. In all of the designs the sulfuric acid regenerant is first passed through the strong acid resin and then through the weak acid resin, ensuring a high degree of acid use.

Carbonic acid is formed in the weak acid column. It decomposes to water and gaseous carbon dioxide with the latter removed in the degasifier. The degasifier is placed after the strong acid resin to take advantage of the shift in the dissolved carbonate equilibrium to carbonic acid with decreasing pH.

The weak base resin is used to replace Cl^- and $SO_4^=$ with OH^-. This resin cannot remove the weakly dissociated carbonic acid from the alkalinity or silicic acid from the silica content in the water. It is easily regenerated with caustic soda requiring about 110 percent of stoichimetry. The strong base resin removes all of the remaining weakly dissociated and strongly dissociated acids, particulary SiO_2, but it's regeneration with caustic soda is not efficient. As with the weak acid/strong acid resin system, the caustic soda is first passed through the strong base resin to the weak base resin, thus ensuring a high degree of chemical usage.

The mixed bed polishes the demineralized water to the desired boiler feed water quality without large swings in pH.

Condensate polishing, although necessary, is minor and its cost is neglected in the calculations.

The cost of the ion exchange system is 9.5 Q¢/hr for Lurgi and 10.5 Q¢/hr for Synthane, where Q is the flow rate in 10^3 lb/hr[2,5]. The energy requirements are assumed to be negligible. The wastewater flow is approximately 6 percent by weight of the feed water.

Reverse Osmosis: This is used to return treatment condensate to the boiler in those Lurgi plants where all of the condensate is not required in the cooling tower (at Beulah, North Dakota and Gillette, Wyoming). It is followed by activated carbon adsorption. The cost of the reverse osmosis system is $19.5\ Q - 0.0043\ Q^2$, where Q is the flow rate in 10^3 lb/hr. Sequestering chemicals are included in the cost. The energy requirements are 10,000 Q Btu/hr. The waste is approximately 10 percent of the feed water.

Activated Carbon Adsorption: The cost is 12 Q ¢/hr, where Q is the feed flow rate in 10^3 lb/hr, and the energy requirements are 4,500 Q Btu/hr. It may be necessary for the carbon bed to precede reverse osmosis so as to prevent membrane fouling, but the arrangement shown in Figure 4-1B is preferable because it reduces the load on the carbon. The waste is negligible.

Process Condensate Treatment

In gasification plants the treated process condensate wastewater will be used as makeup to the cooling tower either by itself or blended with water from the river. Most of the contaminants in the treated process condensate wastewater will end up more concentrated in the blowdown from the cooling tower. However, some contaminants will be reduced in concentration; for example, ammonia will volatalize[6]. Similarly, data from refineries using phenolic wastewaters as makeup to cooling towers show that bio-oxidation of phenol will occur with very high removal efficiencies[7,8,9]. The blowdown from the cooling tower will be used for ash disposal and flue gas desulfurization and/or will be disposed of in a lined evaporation pond. We have assumed that any environmental limitations on phenol and ammonia will be met by suitable treatment of the process condensate. The dirty process condensate is assumed to have the quality shown in Table 4-2.

TABLE 4-2 QUALITY OF PROCESS CONDENSATE FROM SYNTHANE AND LURGI PROCESSES USING SUBBITUMINOUS AND LIGNITE COALS (IN MG/L)

Phenol as C_6H_5OH	6,000
Ammonia as NH_3	7,000
BOD	20,000
Ca^{++}	∿20
Mg^{++}	∿15
HCO_3^-	14,000
Sulfide as S	small
$SO_4^=$	small

The flow rate of the process condensate wastewater is in the range of approximately 1170 to 1780 x 10^3 lb/hr for the Lurgi process and is 1069 x 10^3 lb/hr for the Synthane process.

Phenol Extraction: This is a solvent extraction of phenolic compounds in which the phenols are recovered to help defray the cost of the treatment[2]. The process is used only when the foul condensate is highly concentrated and was used at all plant-sites. The capital investment, maintenance and energy costs are relatively insensitive to the feed concentration and is not less than \$3.00/1000 gals. The value of the recovered phenol is probably limited to its fuel value, about 2.3¢/lb phenol. Ninety-five percent removal of phenol is assumed while BOD is reduced by 2.26 p where p is the influent phenol concentration. The net process cost, in ¢/hr is given by $36\ Q - 0.00219\ y\ Q$, where Q is the feed rate in 10^3 lb/hr and y is the phenol concentration in the feed stream in mg/l. The energy requirements are 10^6 Btu/1000 gals, or 120,000 Q Btu/hr[2]. The waste flows are negligible.

Ammonia Separation: Ammonia is derived from nitrogen in the coal and, except for gasifiers which run so hot that ammonia is not formed, is produced in large quantities whether or not organic molecules are produced. The ammonia is removed from the gas stream in the condensate. Blowing ammonia into the air is not permissible from strong solutions because it is odorous. Ammonia separation is required for all process-site combinations. The process is a distillative, extractive one in which the wastewater is steam stripped and the ammonia recovered from the stripper overhead gases and sold as anhydrous ammonia to defray the costs of treatment[2]. Approximately 20 to 40 trays are required at a steam rate of about 0.9 lb steam per gallon wastewater. Ammonia is reduced to 450 mg/l at which concentration it is a suitable nutrient for subsequent biotreatment. The USS Engineers and Consultants PHOSAM-W process producing anhydrous ammonia was the one selected as it appears to be the most economical of the processes studied. The cost of ammonia stripping and recovery is given by $[43Q - 0.007(y - 450)Q]$ ¢/hr, where it has been assumed that the value of the recovered ammonia is 7¢/lb[2]. The quantity Q is the flow rate of the feed stream in 10^3 lb/hr and y is the concentration of ammonia in mg/l. The energy requirements are 204,000 Q Btu/hr.

Biological Treatment: Most of the organic material in the process condensate is biodegradable. Biological oxidation is a suitable treatment to remove the organic contamination. Two multistage air or high purity oxygen activated sludge tanks used in series give a high removal efficiency. The product water is in the range of 200-500 mg/l BOD and 10-100 mg/l phenols. The most probable cost is in the range 4.5 to 6.5¢/lb BOD removed, factors of 2 to 2.5 times the costs given in Reference 2. These costs are based on the designs made in Reference 10. We have used a cost of 5.0¢/lb BOD removed or 0.0050 y Q ¢/hr when y is the BOD concentration in the feed stream in mg/l and Q is the feed rate in 10^3 lb/hr. The energy requirements are approximately 6 y Q Btu/hr. The waste is approximately 0.1 lb dry waste/lb BOD removed. The cost includes dissolved air flotation and vacuum filtration; the sludge is discharged at 20% of solids.

Cooling Water Treatment

Sand Filter: The water effluent from dissolved air flotation in biotreatment contains up to 100 mg/l suspended solids, which is undesirable for cooling tower feed. The sand filter is assumed to remove 80 percent of the solids and to give a waste backwash stream which is 5 percent solids and which is returned to the biotreatment clarifiers. The operating cost is 0.343 Q ¢/hr where Q is the feed rate in 10^3 lb/hr. The energy costs are negligible. There is no waste since the backwash is returned to the clarifiers for treatment.

Acid Treatment of Cooling Water: Sulfuric acid is used to reduce the alkalinity of the cooling water makeup streams. Since more than 90 percent of the alkalinity must be replaced to do any good, a 100 percent replacement is assumed. The cost is 0.00305 x Q ¢/hr where Q is the flow rate in 10^3 lb/hr and x is the concentration of HCO_3 in mg/l.

Chemicals Added to the Cooling Water: Biocides, anti-corrosion chemicals and suspending agents are added to the cooling water. The total cost is 18.3¢/1000 lb of blowdown or 18.3 Q ¢/hr where Q is the blowdown rate in 10^3 lb/hr.

Lime Soda Softening: This is only used to treat the cooling tower blowdown (see Figure 4-1A). The calcium and magnesium ion concentrations are assumed to be reduced to 20 mg/l and 7 mg/l, respectively, while 1 mg SiO_2 is removed per 2 mg Mg^{++}. The installed cost of the clarifiers, with spare capacity, is assumed to be $500,000[2]. If the interest charge is 12 percent per year and the clarifiers operate for 7,000 hrs per year, the operating charges are 860¢/hr. The waste is based on the dry weight of $CaCO_3$ precipitated with the sludge; it is assumed to be 20% wt. of solids.

Total Costs and Energy Requirements

The total costs and energy requirements for water treatment in standard size Synthane and Lurgi plants are listed in Tables 4-3 and 4-4 and shown graphically in Figures4-2 and 4-3. The results are also normalized with respect to the heating value of the product gas. The water treatment costs range from 8.0 to 12.2¢/10^6 Btu product output, while the energy requirements for water treatment range from 3.9 to 6.5 percent of the product output. The cost of the product fuel will probably be in the range of \$3-4/10^6 Btu so that the water treatment costs, after taking credit for the sale of byproduct ammonia, will not exceed 5 percent of the sale of the product fuel. The total costs and energy requirements for water treatment are primarily dependent on the costs and energy requirements for process condensate treatment. The costs of cooling water treatment comprise the lowest costs while boiler feed water treatment costs are intermediate.

The cost of water treatment for the Synthane plants are insensitive to site. This is attributed to the fact that (1) the costs of boiler feed water and process condensate treatments are the dominant costs of water treatment, and (2) the flows entering and leaving the gasifier and boiler were assumed to be the same for all four sites. The total costs of water treatment for the Lurgi plants are dependent on the quantities of dirty process condensate treated, with the largest amount treated at Beulah and the smallest amount treated at Navajo/Farmington. The quantity of dirty process condensate generated for Lurgi is dependent primarily on the moisture content of the coal (see Figure 4-4). Differences in the cost of water treatment between the Lurgi and Synthane processes at a given site reflect the differences in the cost of both condensate treatment and boiler feed water treatment. The ion exchange costs for the Synthane process are greater than those for the Lurgi process because more steam is required and the quality of the boiler feed water is higher for Synthane. At Beulah, N. Dakota, however, more condensate is produced in the Lurgi process than is needed for makeup to the cooling tower; the excess condensate is treated by reverse osmosis and carbon adsorption for use in the boiler thereby increasing the boiler feed water treatment costs above those for Synthane. On the other hand, the processs condensate treatment costs for the Lurgi process are greater than those for Synthane because more process condensate is generated. The Lurgi process accepts wet coal, while the coal for the Synthane

TABLE 4-3 COSTS OF WATER TREATMENT IN ¢/HR

	Lurgi				Synthane			
	Beulah N.D.	Colstrip Montana	Gillette Wyoming	Navajo/ Farmington New Mexico	Beulah N.D.	Colstrip Montana	Gillette Wyoming	Farmington New Mexico
Boiler Feedwater Treatment								
Ion Exchange	14,350	13,400	14,170	13,880	19,540	19,540	19,540	19,540
Reverse Osmosis	7,220	-	1,530	-	-	-	-	-
Activated Carbon Adsorption	4,390	-	860	-	-	-	-	-
Subtotal	25,960	13,400	16,560	13,880	19,540	19,540	19,540	19,540
Process Condensate Treatment								
Phenol Extraction	40,740	30,020	33,750	26,790	24,440	24,440	24,440	24,440
Ammonia Separation	- 5,080	- 3,740	- 4,210	- 3,340	- 3,050	- 3,050	- 3,050	- 3,050
Biological Treatment	57,380	42,280	47,530	37,740	38,730	38,730	38,730	38,730
Subtotal	93,040	68,560	77,070	61,190	60,120	60,120	60,120	60,120
Cooling Water Treatment								
Filter	540	390	450	310	410	440	450	390
Acid Addition	190	190	160	260	550	480	530	570
Other Chemicals	2,160	2,270	2,310	4,360	3,480	3,660	3,700	3,830
Lime-Soda Softening	-	860	-	-	860	860	860	860
Subtotal	2,890	3,710	2,920	4,930	5,300	5,440	5,540	5,650
TOTAL	121,890	85,670	96,550	80,000	84,960	85,100	85,200	85,310
TOTAL (¢/10^6 Btu)	12.2	8.6	9.7	8.0	8.5	8.5	8.5	8.5

TABLE 4-4 ENERGY REQUIREMENTS FOR WATER TREATMENT IN 10^6 BTU/HR

	Lurgi				Synthane			
	Beulah N.D.	Colstrip Montana	Gillette Wyoming	Navajo/ Farmington New Mexico	Beulah N.D.	Colstrip Montana	Gillette Wyoming	Farmington New Mexico
Boiler Feedwater Treatment								
Ion Exchange	-	-	-	-	-	-	-	-
Reverse Osmosis	4	-	1	-	-	-	-	-
Activated Carbon Adsorption	2	-	0.3	-	-	-	-	-
Subtotal	6	-	1.3	-	-	-	-	-
Process Condensate Treatment								
Phenol Extraction	214	158	177	141	128	128	128	128
Ammonia Separation	364	268	301	239	218	218	218	218
Biological Treatment	69	51	57	45	46	46	46	46
Subtotal	647	477	534	425	392	392	392	392
Cooling Water Treatment								
Filter	-	-	-	-	-	-	-	-
Acid Addition	-	-	-	-	-	-	-	-
Other Chemicals	-	-	-	-	-	-	-	-
Lime-Soda Softening	-	-	-	-	-	-	-	-
Subtotal	-	-	-	-	-	-	-	-
TOTAL	653	477	535	425	392	392	392	392
TOTAL (% of product energy)	6.5	4.8	5.4	4.3	3.9	3.9	3.9	3.9

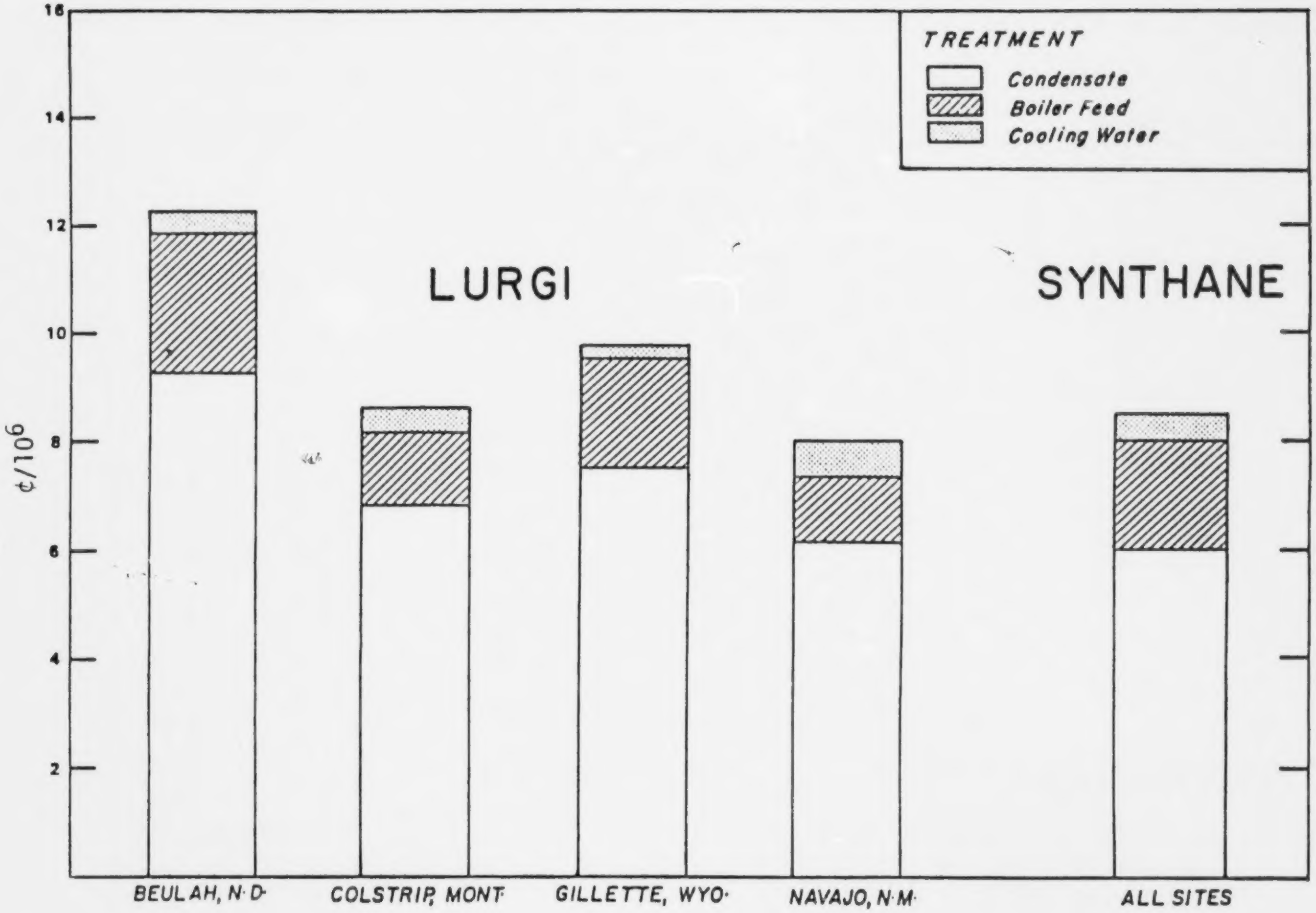


Figure 4-2. Cost of water treatment in ¢/10^6 Btu of product.

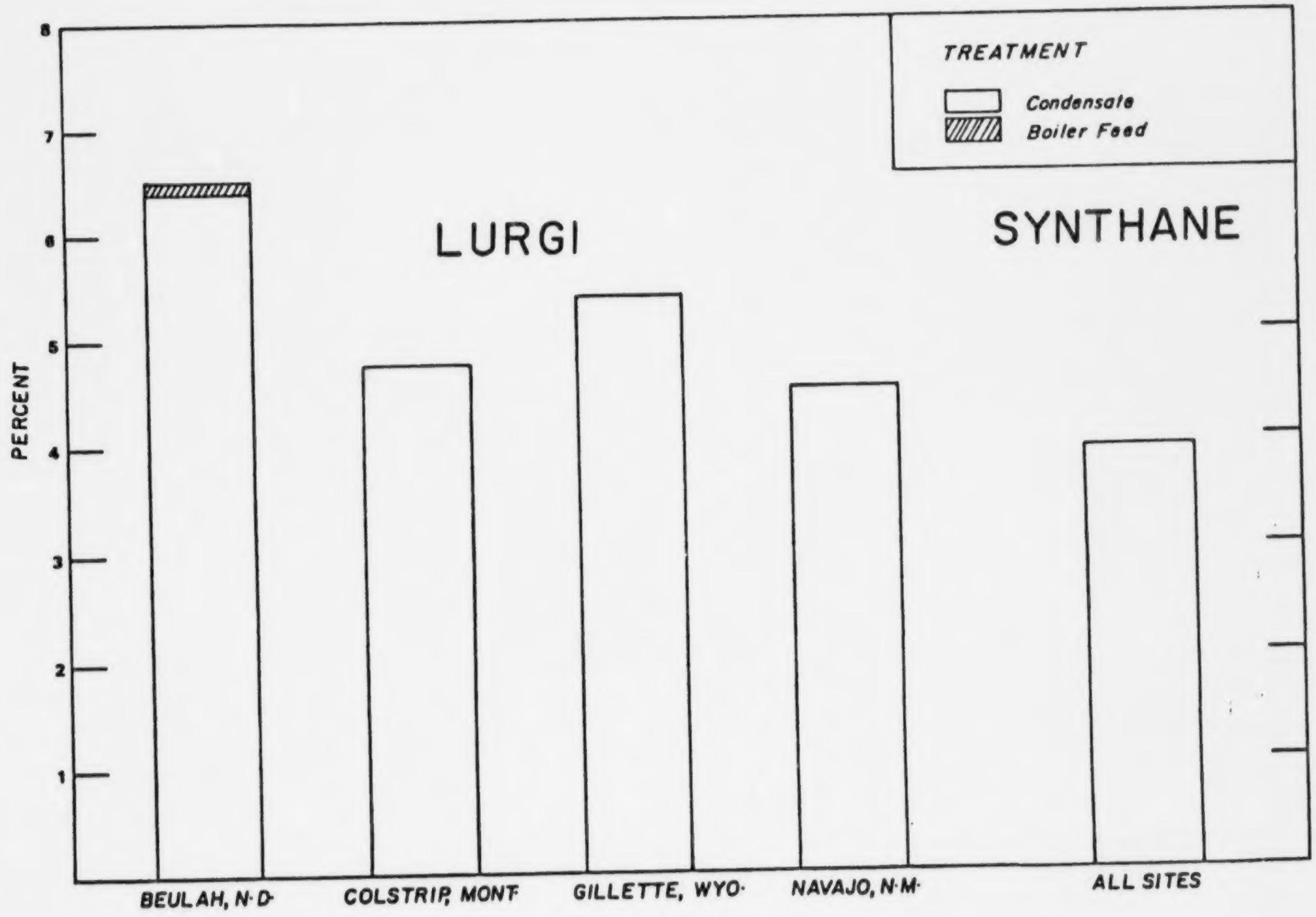


Figure 4-3. Energy consumed for water treatment in percent of the heating value of product fuel.

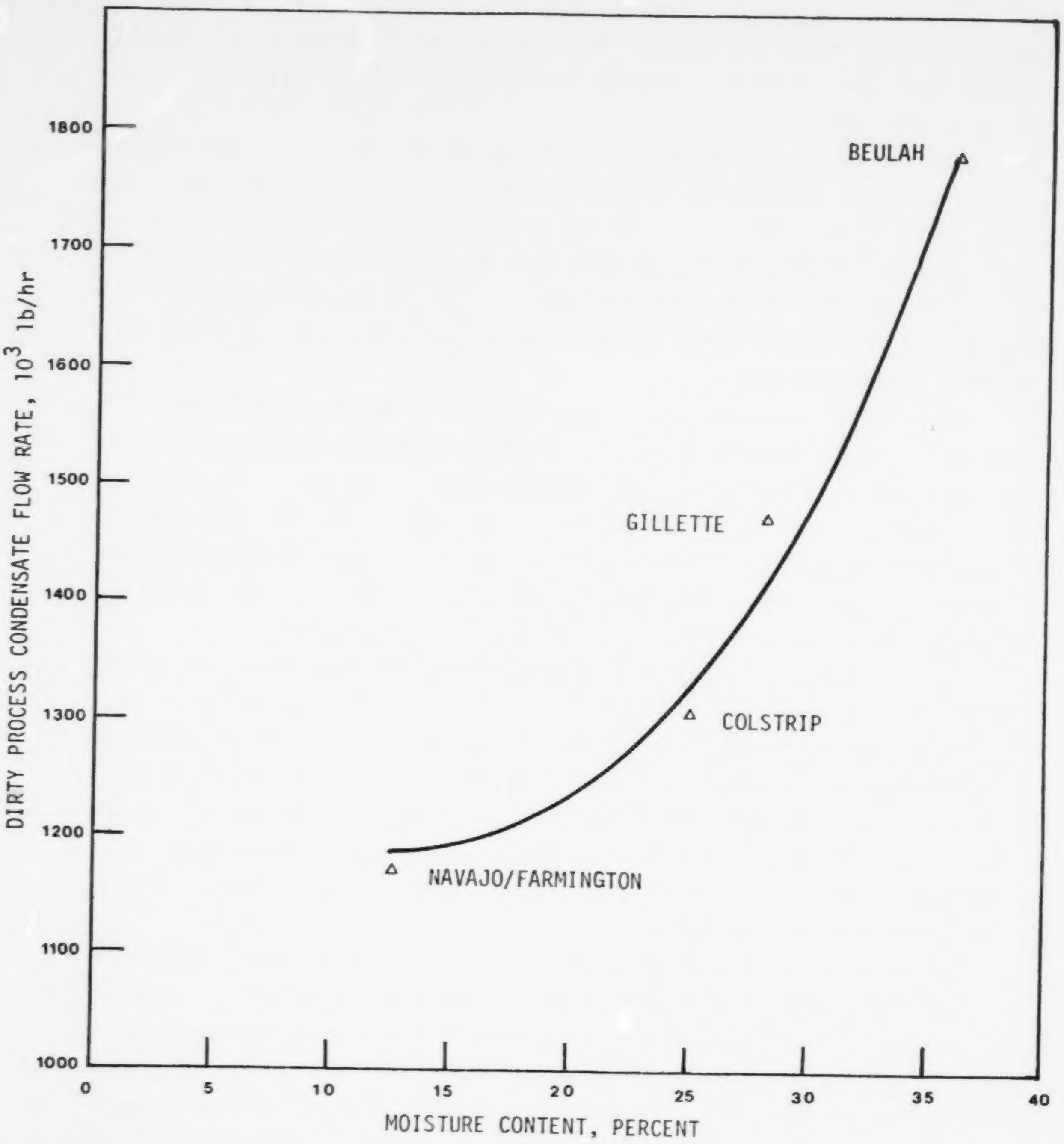


Figure 4-4. Quantity of dirty process condensate generated in a 250 X 10^6 scf/day Lurgi plant as a funtion of moisture content of coal.

process must be dried and the coal moisture is lost by evaporation. As a result, the costs of water treatment for Synthane lie between the minimum and maximum costs for Lurgi.

In a similar manner the energy requirements for water treatment primarily are dependent on the quantity of process condensate generated and, to a lesser extent, on the concentration of the contaminants to be removed. For the Lurgi and Synthane processes we have assumed that the qualities of the process condensate streams are the same (see Table 4-2). For all of the processes the energy required for the water treatment plants is controlled by the amount needed for ammonia separation.

In Section 3 we defined three cooling options representing different degrees of wet evaporative cooling for turbine condensers and interstage coolers. The costs and energy requirements shown on Tables 4-3 and 4-4 correspond to a high degree of wet cooling for the Synthane process and an intermediate degree of wet cooling for the Lurgi process. We would like to estimate the water treatment costs and energy requirements for all three levels of water consumption.

For all three cooling options we assume that the foul condensate wastewater will be treated for use in the cooling tower or as makeup to the boiler. Thus, the costs and energy requirements for process condensate treatment will be unaffected by the choice of the cooling option. Tables 4-3 and 4-4 show that the total costs and energy requirements are mainly dependent on the costs and energy requirements of process condensate treatment. Thus, the total costs and energy requirements are not expected to vary greatly with the cooling water consumed in evaporation.

The costs of cooling water treatment varies almost proportionally to the cooling tower makeup so that a reduction in the quantity of water evaporated for cooling will lead to a similar reduction in the cost of cooling water treatment. However, the cost of cooling water treatment does not exceed 7 percent of the total cost of water treatment. If the cooling water requirements are substantially reduced, then the process condensate may be sufficient to meet all of the needs of the cooling tower. The excess wastewater may be further treated for boiler water makeup (see Figure 4-1B) by reverse osmosis and carbon adsorption, increasing the costs of boiler water makeup. Thus it is difficult to generalize the effect of cooling water consumption on the costs of wastewater treatment.

For the Synthane process, the effect of going from a high degree of wet cooling to minimum practical cooling is to reduce the costs of water treatment by 0.1 to 0.15¢/10^6 Btu with virtually no change in the energy requirements. For the Lurgi process the effect of going to a high degree of water cooling from intermediate cooling is to vary the costs of water treatment by -1.0 to +0.25¢/10^6 Btu, while the effect of going from intermediate cooling to minimum practical cooling is to vary the costs from -0.07 to +0.77¢/10^6 Btu. Similarly, there is very little change in the energy requirements. In all cases the variation in the water treatment costs with cooling option do not exceed 10 per cent of the costs shown in Table 4-3.

4.3 BLOWDOWN TREATMENT AND DISPOSAL

The overall effect of energy development on the Colorado River Basin is to reduce the total salt loading or total salt content (in pounds of salt per unit time) of the river and to increase the salinity concentration in the downstream reaches of the river[11]. The latter effect is attributable to the reduced flow of water for dilution because of the large consumptive uses of water for cooling within the conversion plants. Under the regulations of the Colorado River Basin Salinity Control Forum, "the objective for industrial discharges shall be a no-salt return policy wherever practicable."[12] In particular large coal-fired thermal electric generating plants have been designed to eliminate the return of cooling tower blowdown water to the Colorado River. This necessitates costly treatment and disposal procedures to insure no return (zero discharge) to the receiving water. However, if the blowdown is returned to the Colorado, the salinity concentration increase may be reduced because of the increased dilution water, but at the expense of increased salt loading. The cost to treat and return the blowdown to the Colorado River will probably be lower than the cost of zero discharge.

We will leave the trade-off between increased dilution and increased salt loading to other studies. In this section we are concerned about the trade-off between the cost to treat and dispose of the blowdown and the quantity and concentration of the blowdown, particularly with respect to total dissolved solids. We have only considered blowdown streams from the cooling tower and not other waste streams within the plant.

We have estimated the costs of blowdown treatment and disposal for two coal gasification processes, namely Lurgi and Synthane, and for steam electric power generation at three specific sites: Beulah, North Dakota; Gillette, Wyoming and Navajo/Farmington, New Mexico with and without zero discharge. The Lurgi and Synthane plants each generate 250 x 10^6 scfd of pipeline gas at a 90 percent load factor and the steam electric plant generates 3,000 MWe at a 70 percent load factor. We have not included the auxiliary costs associated with piping, instrumentation, civil, structural and other detailed engineering costs, since we are primarily concerned with the relative costs associated with treatment and disposal. Furthermore, we have assumed for the coal gasification plants that the process condensate has been treated sufficiently to remove ammonia by ammonia stripping and organics by solvent extraction and biotreatment (as described in Section 4.2) prior to addition to the cooling water system as makeup so that disposal of the blowdown with the coal ash, or into an evaporation pond, or into the receiving water, is environmentally acceptable. Similarly, the blowdown from the cooling tower of a steam electric power plant is assumed to contain non-toxic substances. Finally, only a limited number of blowdown treatment procedures have been considered. No attempt has been made to optimize the costs by considering a wide range of treatment procedures. An excellent review of blowdown treatment procedures and costs is given in Reference 13.

Figure 4-5 is a general drawing showing the nomenclature. We only consider the makeup water to the cooling tower, Q_1, and not the total water taken out of the river for all consumptive uses. In the case of zero discharge, $Q_2 = 0$, the cooling tower blowdown is treated, part of the blowdown is recycled and part is disposed of in a solar evaporation pond. In the case of effluent discharge, the blowdown is treated and either part or all is discharged to the receiving water.

Six cases were considered, each with the cooling tower operated at either very few (N=2.5) cycles of concentration or at very high (N=10) cycles of concentration. It was assumed that when the cooling tower was operated at only 2.5 cycles of concentration, chemical treatment of the circulating cooling water was the only treatment necessary. The high cycles example assumed was 10 cycles of concentration, which is typical of design practice in power plants

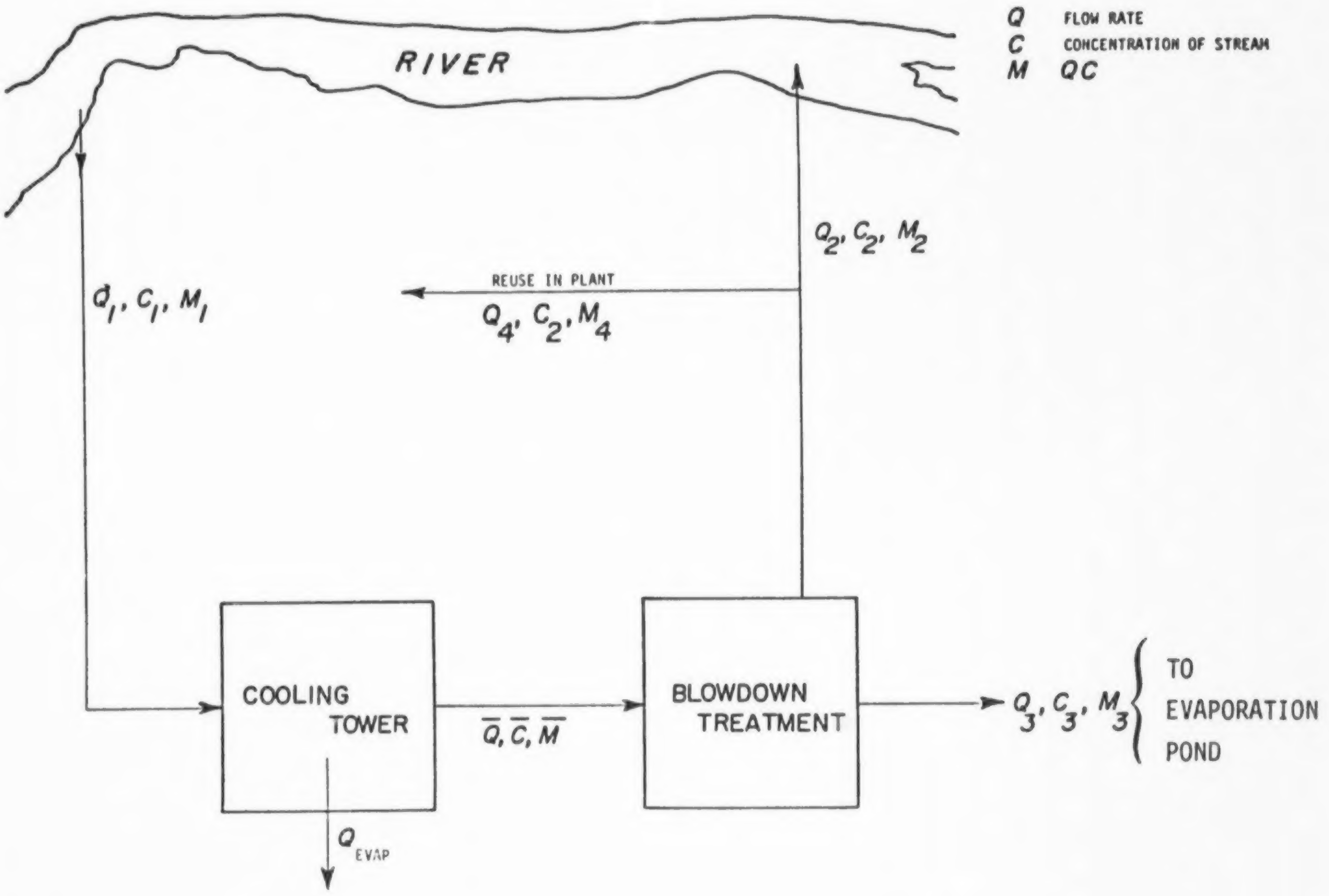
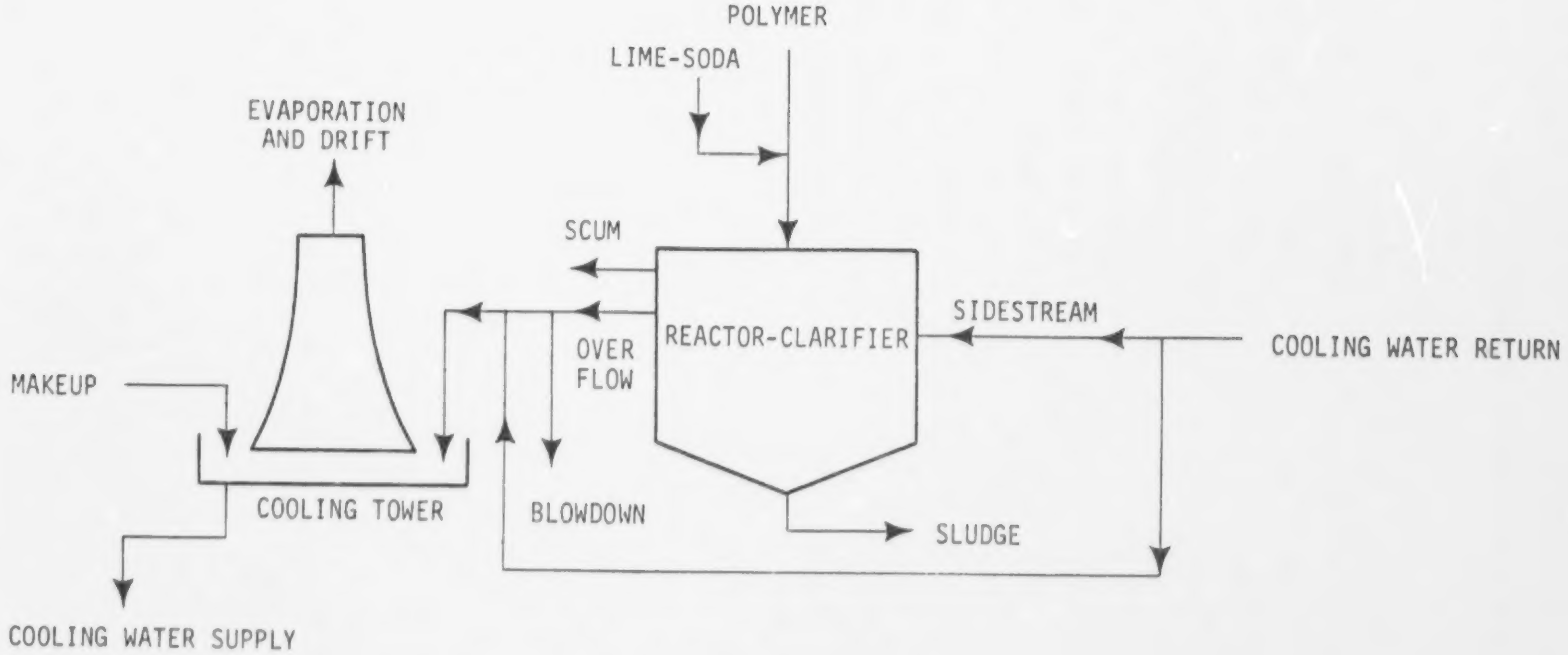

Q FLOW RATE
C CONCENTRATION OF STREAM
M QC
RIVER
Q_1, C_1, M_1
Q_2, C_2, M_2
REUSE IN PLANT
Q_4, C_2, M_4
COOLING TOWER
$\overline{Q}, \overline{C}, \overline{M}$
BLOWDOWN TREATMENT
Q_3, C_3, M_3
TO EVAPORATION POND
Q_{EVAP}

Figure 4-5. Flow diagram for blowdown treatment and disposal.

located in the semi-arid West. To provide 10 cycles of concentration, sidestream softening is required. By substituting a reactor-clarifier with multiple chemical feeds for the traditional lime softening clarifier, several of the treatments required for effluent discharge can be incorporated into the sidestream treatment (see Figure 4-6). If the cooling tower blowdown stream is taken from the overflow of the sidestream softening reactor-clarifier, separate treatment for the removal of heavy metals, oil and grease and organics can be eliminated. Lime-soda treatment in the reactor-clarifier will precipitate heavy metals and polymer addition will remove those organics not originally eliminated from the process condensate wastewater by biotreatment and/or extraction prior to addition to the cooling tower makeup. Residual quantities of oil and grease can be removed by designing the reactor-clarifier with a scum skimmer and alum feed. After sidestream treatment the blowdown will only require sand filtration for settable solids removal, pH adjustment via acid addition and, for different cases, dissolved salts reduction. For all cases, the river water first goes into a settling pond which is used to remove suspended solids and provide storage capacity for the entire plant. The cost of the settling pond was not considered since it would be approximately the same for all cases.

The six cases are summarized in Table 4-5. Details are given on the figures listed. Case I, shown in Figures 4-7 and 4-8 is for effluent discharge into the receiving water when TDS reduction is not required. Case II, shown in Figure 4-9 is the same as Case I, but a single stage electrodialysis membrane process is used for TDS reduction. The concentrate from the electrodialysis system goes to a solar evaporation pond for disposal, while the permeate is discharged into the receiving water. Cases III, IV, V and VI are cases of zero discharge. In Case III, shown in Figure 4-10, all of the blowdown from the sidestream clarifier-reactor is disposed of in a lined solar pond for evaporation to dryness. In Case IV, also shown in Figure 4-10, all of the blowdown from the sidestream clarifier-reactor is used for in-plant uses, such as ash disposal or fly ash removal, without any reduction in TDS. Case V, which is shown in Figure 4-11, uses 3-stage electrodialysis which provides almost 90% solids removal while recovering 90% of the cooling tower blowdown.



POLYMER
LIME-SODA
EVAPORATION AND DRIFT
SCUM
SIDESTREAM
REACTOR-CLARIFIER
COOLING WATER RETURN
MAKEUP
OVER FLOW
COOLING TOWER
BLOWDOWN
SLUDGE
COOLING WATER SUPPLY

Figure 4-6 Incorporation of blowdown treatment into sidestream treatment.

TABLE 4-5. SUMMARY OF CASES STUDIED

Case	Figure	Cycles of Concentration	Blowdown Treatment	Discharge
I A	4-7	2.5	None	Yes
I B	4-8	10	None	Yes
II A	4-9	2.5	Single-Stage	Yes
II B	4-9	10	Electrodialysis	Yes
III A	4-10	2.5	Evaporation Pond	No
III B	4-10	10	Evaporation Pond	No
IV A	4-10	2.5	Used in Plant	No
IV B	4-10	10	Used in Plant	No
V A	4-11	2.5	Three-Stage	No
V B	4-11	10	Electrodialysis	No
VI A	4-12	2.5	Brine Concentrator	No
VI B	4-12	10	Brine Concentrator	No

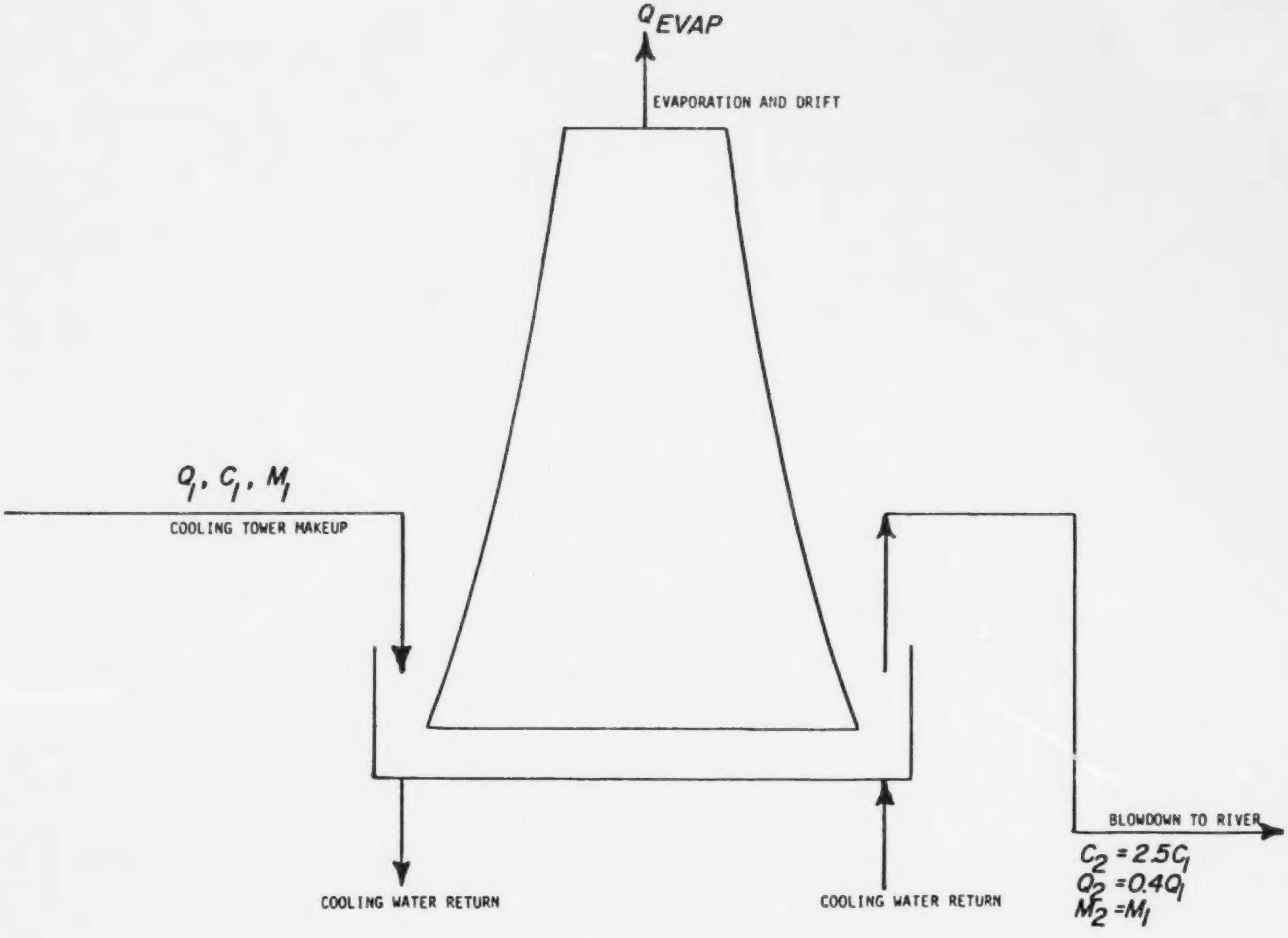

Q_{EVAP}
EVAPORATION AND DRIFT
Q_1, C_1, M_1
COOLING TOWER MAKEUP
COOLING WATER RETURN
COOLING WATER RETURN
BLOWDOWN TO RIVER
$C_2 = 2.5C_1$
$Q_2 = 0.4Q_1$
$M_2 = M_1$

Figure 4-7 Case I. Effluent discharge to river at low cycles of concentration.

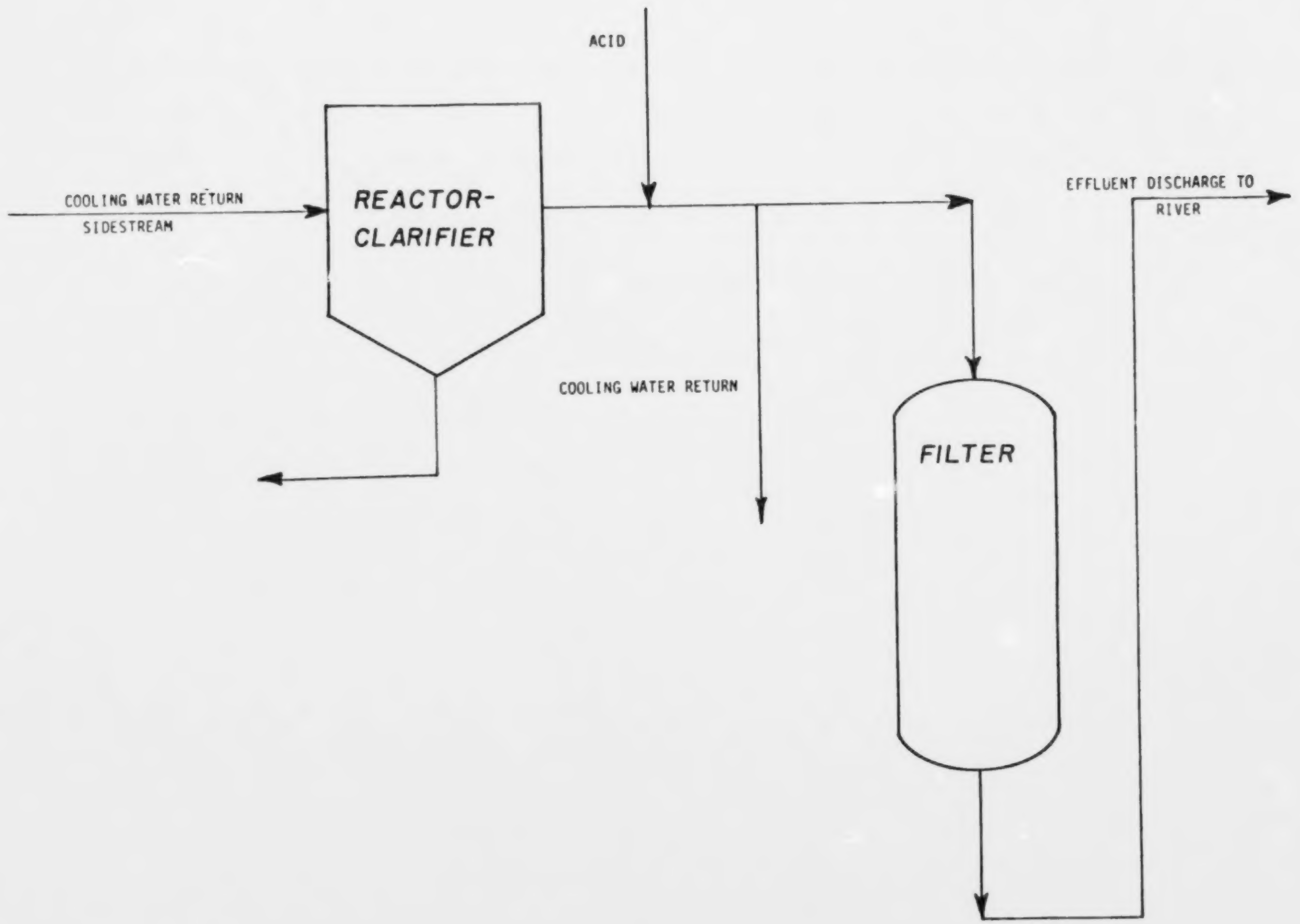

ACID
COOLING WATER RETURN
SIDESTREAM
REACTOR-
CLARIFIER
COOLING WATER RETURN
FILTER
EFFLUENT DISCHARGE TO
RIVER

Figure 4-8 Case I. Effluent discharge to river at high cycles of concentration. TDS reduction not required.

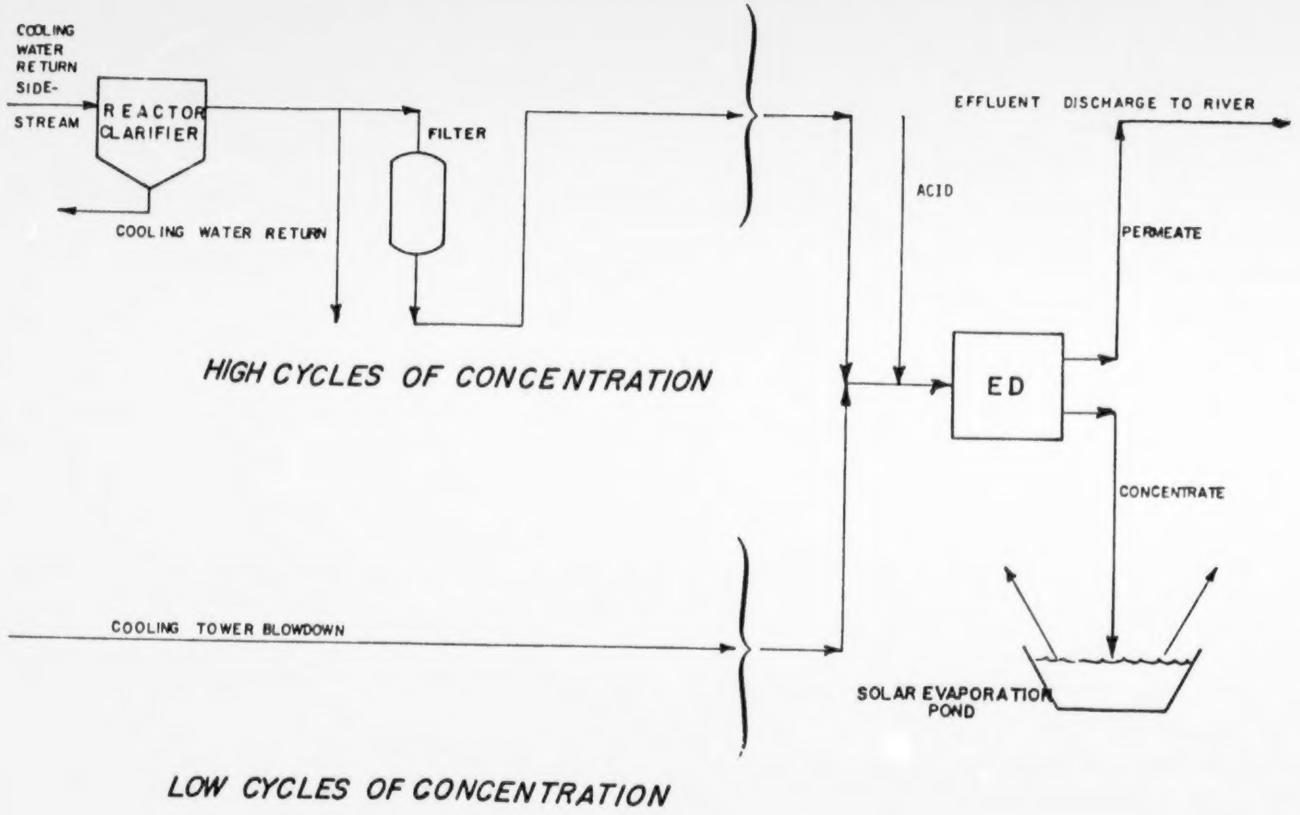

COOLING WATER RETURN SIDE-STREAM
REACTOR CLARIFIER
COOLING WATER RETURN
FILTER
HIGH CYCLES OF CONCENTRATION
COOLING TOWER BLOWDOWN
LOW CYCLES OF CONCENTRATION
ACID
ED
EFFLUENT DISCHARGE TO RIVER
PERMEATE
CONCENTRATE
SOLAR EVAPORATION POND

Figure 4-9 Case II. Effluent discharge to river. TDS reduction via single stage electrodialysis membrane system.

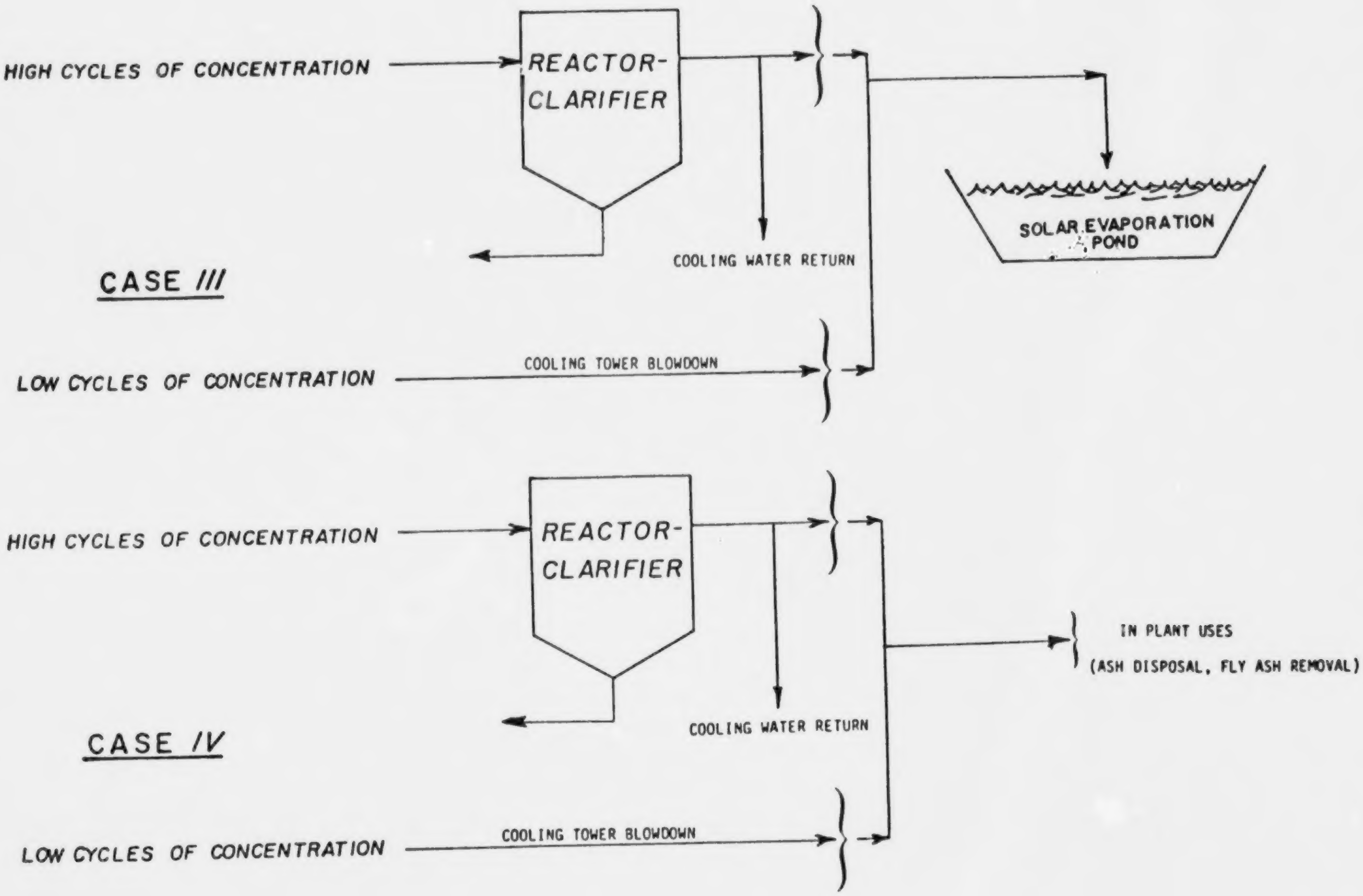

HIGH CYCLES OF CONCENTRATION
REACTOR-CLARIFIER
COOLING WATER RETURN
SOLAR EVAPORATION POND
CASE III
LOW CYCLES OF CONCENTRATION
COOLING TOWER BLOWDOWN
HIGH CYCLES OF CONCENTRATION
REACTOR-CLARIFIER
COOLING WATER RETURN
IN PLANT USES
(ASH DISPOSAL, FLY ASH REMOVAL)
CASE IV
LOW CYCLES OF CONCENTRATION
COOLING TOWER BLOWDOWN

Figure 4-10 Cases III and IV. Zero discharge. Blowdown used for in-plant uses or disposed of in a solar evaporation pond.

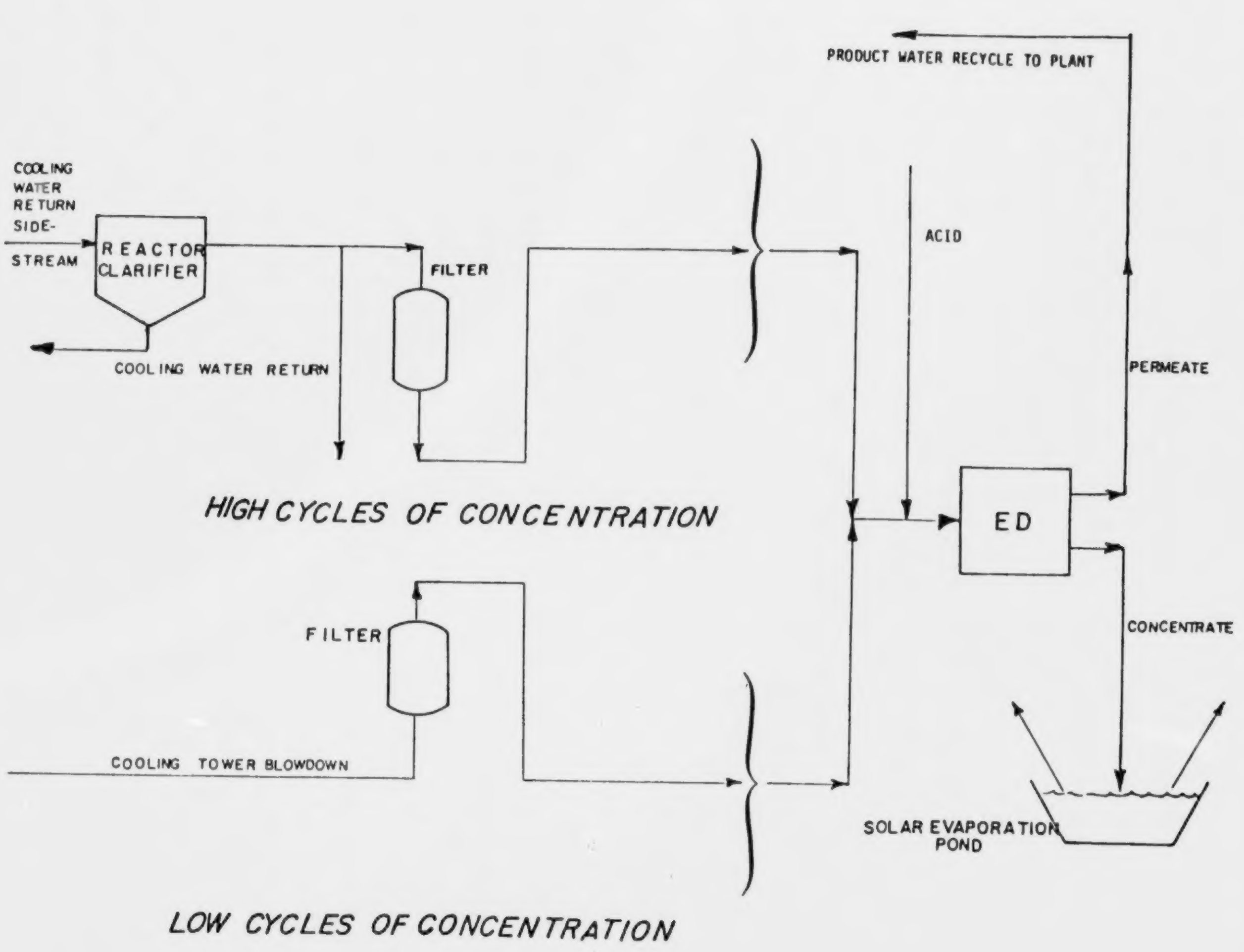

PRODUCT WATER RECYCLE TO PLANT
COOLING WATER RETURN SIDE-STREAM
REACTOR CLARIFIER
FILTER
COOLING WATER RETURN
ACID
PERMEATE
ED
HIGH CYCLES OF CONCENTRATION
FILTER
CONCENTRATE
COOLING TOWER BLOWDOWN
SOLAR EVAPORATION POND
LOW CYCLES OF CONCENTRATION

Figure 4-11 Case V. Zero discharge incorporating three stage electrodialysis with wastewater recycle.

In order to protect the membrane from sedimentation and scale deposits, the blowdown is sand filtered and the pH adjusted with acid prior to electrodialysis treatment. The product filtrate from the electrodialysis modules is recycled back to the cooling tower or boilers while the concentrate is pumped to the solar ponds for evaporation. An alternative approach, which is used extensively in power plants in the West, is to reduce the dissolved solids by vapor compression using the system developed by Resources Conservation Co.[14] Case VI, shown in Figure 4-12, provides for a twenty-fold concentration of the cooling tower blowdown and 96 percent recovery of the wastewater. The condensate contains less than 10 ppm total dissolved solids and is usually used for high quality water uses within the plant, such as for boiler water makeup. The brine concentrate is sent to the solar ponds for evaporation.

Table 4-6 presents the calculated cooling tower blowdown and makeup rates for each process-site combination. The evaporation, drift and waste treatment flow rates are taken from Table 4-1 for the Synthane and Lurgi processes and from Section 10 of Reference 1 for steam power generation. The blowdown and makeup flow rates are calculated for $N = 2.5$ and $N = 10$ cycles of concentration.

Table 4-7 lists the flow rates as a fraction of the evaporation rate, and the concentrations and total salt content of each stream as a fraction or multiple of the makeup intake quantities (see Figure 4-5). Those cases in which an evaporation pond is used have a higher total plant consumption of water than those cases where a pond is not used. Cases II, III, V and VI require a higher water consumption than Cases I and IV; Case III has the highest consumption. In making this statement, we assume that water recycled for other plant uses decrease the total water taken out of the river (not shown on Figure 4-5).

Relative total water consumptions are shown in the last column of Table 4-7, $(Q_1 - Q_2)/Q_{evap}$. Water consumption is minimized by minimizing the water evaporated in a pond (because this is not a useful consumption) and by using higher cycles of concentration in the cooling tower.

The fraction of salt taken from the river which is returned to the river is shown in Table 4-7 in the column headed, M_2/M_1. For the zero discharge Cases III through VI, this is zero. The fraction of the salt taken from the river which is disposed of in an evaporation pond is shown in the column, M_3/M_1. When $M_2/M_1 + M_3/M_1$ does not equal 1, it is because some salt is disposed of within the plant, usually with ash. In Case IV all the salt is disposed of within the plant.

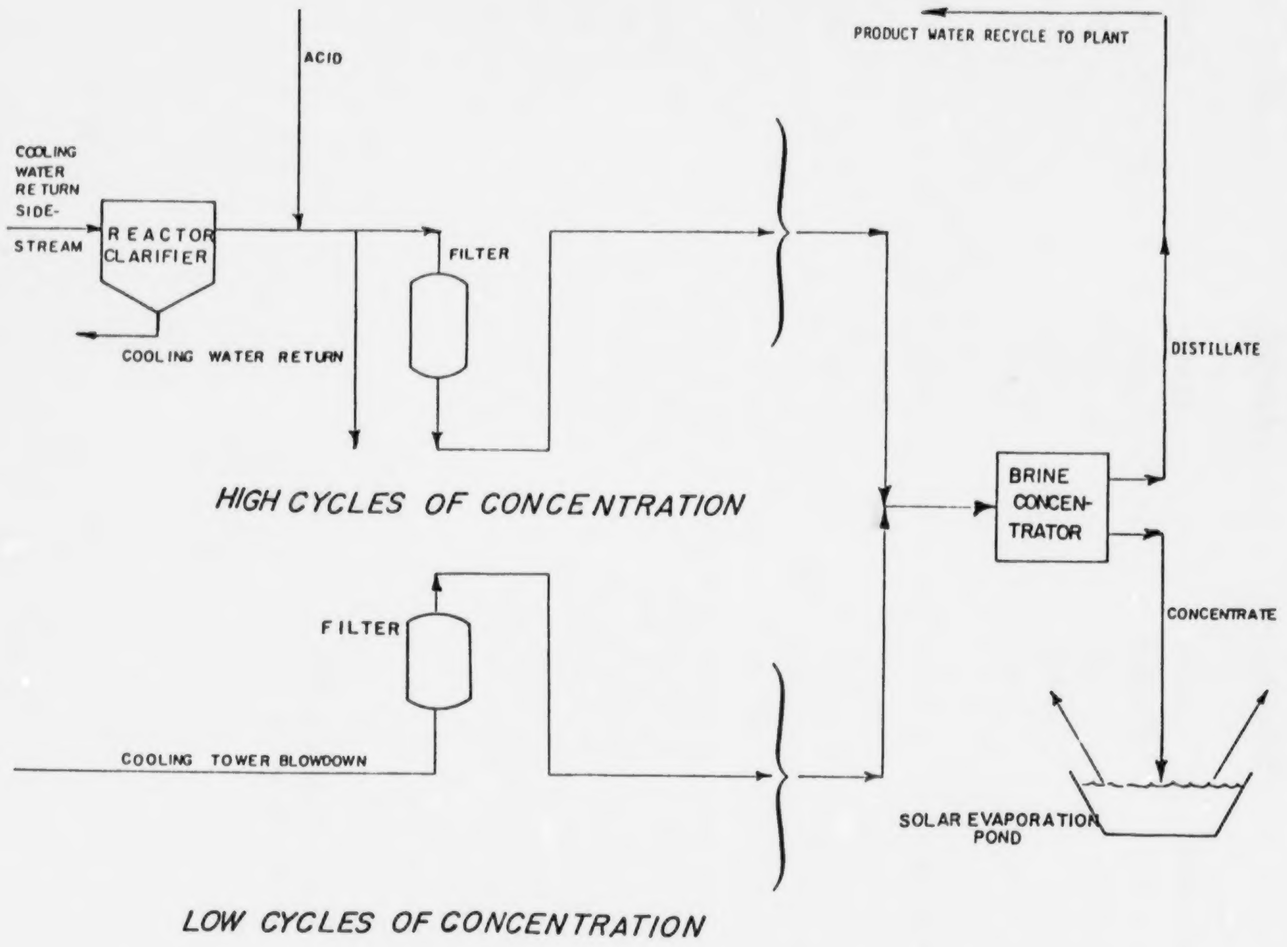

ACID
COOLING WATER RETURN SIDE-STREAM
REACTOR CLARIFIER
FILTER
COOLING WATER RETURN
HIGH CYCLES OF CONCENTRATION
FILTER
COOLING TOWER BLOWDOWN
LOW CYCLES OF CONCENTRATION
PRODUCT WATER RECYCLE TO PLANT
DISTILLATE
BRINE CONCENTRATOR
CONCENTRATE
SOLAR EVAPORATION POND

Figure 4-12 Case VI. Zero discharge incorporating vapor compression brine concentration with wastewater recycle.

TABLE 4-6 FLOW RATES IN GALLONS PER STREAM MINUTE

		Beulah, North Dakota	Gillette, Wyoming	Navajo/Farmington New Mexico
Lurgi				
Evaporation & Drift*		2,182	2,340	2,030
Blowdown:	N** = 2.5	1,455	1,560	1,353
	N = 10.0	242	260	226
Makeup:	N = 2.5	3,637	3,900	3,383
	N = 10.0	2,424	2,600	2,256
Synthane				
Evaporation & Drift*		3,516	3,718	3,854
Blowdown:	N = 2.5	2,344	2,479	2,569
	N = 10.0	391	413	428
Makeup:	N = 2.5	5,860	6,197	6,423
	N = 10.0	3,907	4,131	4,282
Electric Power				
Evaporation & Drift***		19,137	20,164	20,936
Blowdown:	N = 2.5	12,758	13,443	13,957
	N = 10.0	2,126	2,240	2,326
Makeup:	N = 2.5	31,895	33,607	34,893
	N = 10.0	21,263	22,404	23,362

---

*From Table 4-1

**N is cycles of concentration

***From Section 10 of Reference 1.

TABLE 4-7 FLOW RATES, CONCENTRATIONS AND SALT LOADING OF WASTE STREAMS

Case	N	Q_1/Q_{evap}	Q_2/Q_{evap}	C_2/C_1	M_2/M_1	$\frac{Q_3}{Q_{evap}}$	$\frac{Q_4}{Q_{evap}}$	$\frac{C_3}{C_1}$	$\frac{M_3}{M_1}$	$\frac{Q_1 - Q_2}{Q_{evap}}$
I	2.5	1.6667	0.6667	2.5	1	0	0	0	0	1
	10	1.1111	0.1111	10	1	0	0	0	0	1
II	2.5	1.6667	0.6	1.25	0.45	0.0667	0	13.75	0.55	1.0667
	10	1.1111	0.1	5	0.45	0.0111	0	55	0.55	1.0111
III	2.5	1.6667	0	0	0	0.6667	0	2.5	1	1.6667
	10	1.1111	0	0	0	0.1111	0	10	1	1.1111
IV	2.5	1.6667	0	0	0	0	0.6667	2.5	0	1
	10	1.1111	0	0	0	0	0.1111	10	0	1
V	2.5	1.6667	0	0.3125	0	0.0667	0.6	22.1875	0.8875	1.0667
	10	1.1111	0	1.25	0	0.0111	0.1	88.75	0.8875	1.0111
VI	2.5	1.6667	0	0.00521	0	0.0267	0.640	62.375	0.998	1.0267
	10	1.1111	0	0.02083	0	0.00444	0.1067	249.5	0.998	1.0044

A negative return of salt to the river can be made by returning water with a lower salinity than the river water. This is expensive.

The capital costs of the major equipment components are given in Table 4-8. The costs are based upon data presented in Appendix 11 of Reference 5 and include installation. The equipment was sized for the stream flow rates given in Table 4-6. A cost of $40,000 per acre was assumed for clay-lined solar evaporation ponds with an adequate ground water monitoring system. This cost is highly variable and very site dependent. The size of the evaporation pond is determined by the net evaporation rate. The number of acres required for each gpm of blowdown to be disposed of was calculated as follows: North Dakota, 0.64 acres/gpm; Wyoming, 0.48 acres/gpm and New Mexico, 0.36 acres/gpm. A capital cost of $6 per gallon per day was assumed for brine concentration. The capital cost for each case and for each plant-site combination is given in Table 4-9.

The lowest capital costs are for those cases where there is no limitation on the method of disposing of the blowdown. This occurs for Case I, where the blowdown is discharged directly to the receiving water, and for Case IV where the blowdown is used in the plant. The capital costs for the other cases increases in the following order: Case II, Case V, Case VI and Case III. For Case II TDS reduction was required for effluent discharge to the receiving water. Zero discharge was specified for the other three cases with final treatment and disposal of the blowdown taking place in evaporation ponds. Of the last three cases, the least expensive case was for blowdown treatment by electrodialysis and the most expensive case was for complete blowdown disposal in evaporation ponds; brine concentration fell in between the two cases.

The capital cost of the various disposal systems are strongly dependent on the flow rate of the blowdown streams. Thus, the capital cost of the treatment systems increases as the cycles of concentration decreases and as the flow rate decreases in the following order: Lurgi, Synthane and electric power generation (see Table 4-6). For a given process the variation of capital cost with site was due to the variation in the quantity of water treated.

TABLE 4- 8 CAPITAL COST OF MAJOR EQUIPMENT COMPONENTS IN THOUSANDS OF DOLLARS

N = 2.5 Cycles of Concentration

	Lurgi			Synthane			Electric Generation		
Equipment	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
1. Reactor-Clarifier	-	-	-	-	-	-	-	-	-
2. Sand Filter	-	-	-	-	-	-	-	-	-
3. Solar Ponds (Case 3)	37,570	30,132	19,896	60,800	48,200	37,540	329,160	259,860	202,980
4. Solar Ponds (Case 2,5)	3,752	3,012	1,992	6,078	4,818	3,756	32,916	25,986	20,298
5. Solar Ponds (Case 6)	1,503	1,212	792	2,430	1,926	1,500	13,140	10,380	8,100
6. Electrodialysis (Case 2)	850	820	790	1,050	1,200	1,200	3,720	3,920	4,070
7. Electrodialysis (Case 5)	1,414	1,365	1,315	1,822	1,930	2,000	7,440	7,840	8,140
8. Brine Concentr. (Case 6)	12,560	13,500	11,700	20,280	21,420	22,200	110,220	116,120	120,600

Case I = 1 + 2
Case II = 1 + 2 + 4 + 6
Case III = 1 + 3
Case IV = 1
Case V = 1 + 2 + 4 + 7
Case VI = 1 + 2 + 5 + 8

(Continued)

TABLE 4-8 (concluded)

N = 10 Cycles of Concentration

Equipment	Lurgi			Synthane			Electric Generation		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
1. Reactor-Clarifier	182	196	171	289	312	323	821	826	831
2. Sand Filter	24	26	23	39	41	43	213	224	233
3. Solar Ponds (Case 3)	6,249	5,022	3,316	10,133	8,033	6,256	54,860	43,310	33,830
4. Solar Ponds (Case 2,5)	624	502	332	1,013	803	626	5,486	4,331	3,383
5. Solar Ponds (Case 6)	250	202	132	405	321	250	2,190	1,730	1,350
6. Electrodialysis (Case 2)	306	314	294	380	386	374	1,030	1,000	1,085
7. Electrodialysis (Case 5)	470	505	453	570	602	607	1,770	1,742	1,810
8. Brine Concentr. (Case 6)	2,090	2,250	1,950	3,380	3,570	3,700	18,370	19,354	20,100

Case I = 1 + 2
Case II = 1 + 2 + 4 + 6
Case III = 1 + 3
Case IV = 1
Case V = 1 + 2 + 4 + 7
Case VI = 1 + 2 + 5 + 8

TABLE 4- 9 CAPITAL COST OF TREATMENT AND DISPOSAL SYSTEMS IN THOUSAND OF DOLLARS

N = 2.5 Cycles of Concentration

	Lurgi			Synthane			Electric Generation		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	-	-	-	-	-	-	-	-	-
Case II	4,602	3,832	2,782	7,128	6,018	4,956	36,636	29,906	24,368
Case III	37,570	30,132	19,896	60,800	48,200	37,540	329,160	259,860	202,980
Case IV	-	-	-	-	-	-	-	-	-
Case V	5,166	4,377	3,307	7,900	6,748	5,756	40,356	33,826	28,438
Case VI	14,063	14,712	12,492	22,710	23,346	23,700	123,360	124,500	128,700

N = 10 Cycles of Concentration

Case I	206	222	194	328	353	366	1,034	1,050	1,064
Case II	1,136	1,038	820	1,721	1,542	1,366	7,550	6,381	5,532
Case III	6,431	5,218	3,487	10,422	8,345	6,579	55,681	44,136	34,661
Case IV	182	196	171	289	312	323	821	826	831
Case V	1,300	1,229	979	1,911	1,758	1,599	8,290	7,123	6,257
Case VI	2,546	2,674	2,276	4,113	4,244	4,316	21,594	22,134	26,982

The operating costs shown on Table 4-10 include a general maintenance cost of 5% of capital per year, the cost of chemical addition estimated to be $0.50/1000 gallons of blowdown at 2.5 cycles of concentration and $1.00/1000 gallons of blowdown at 10 cycles of concentration, the cost of membrane replacement and power for those cases utilizing electrodialysis estimated at 30¢/1000 gals of blowdown processed, the cost of energy, labor and chemicals for brine concentration estimated at $4.00/1000 gals of blowdown, and a discount of $1.00/1000 gals for water recycled to the process in Cases V and VI, , which represents the savings in water in substituting for an equal quantity of raw makeup water which would otherwise have to be treated for suspended solids, pH and dissolved solids to be equivalent in quality to the recycled water. The flow rates used in estimating the operating costs are based on a load factor of 90% for coal gasification and 70% for electric power generation.

The total amortization and operating costs are shown in Table 4-11 in thousands of dollars per year. The amortization costs were based on a fixed charge rate of 12 percent of the capital costs per year and were added to the operating costs shown in Table 4-10. In general the total amortization operating costs follow the same trend as the capital costs. However, if credit is taken for recycle, the costs for Case V are lower than those for Case II. Another exception is that there are some situations in which the cost of brine concentration exceed those for treatment of the blowdown by solar evaporation only (Case III).

We should note that brine concentration, although expensive, is a proven method which is very reliable and which is used extensively on many zero discharge electric power plants in the West. It does offer investment tax credit advantages over solar pond evaporation. In addition the product water from the brine concentrator is of a better quality than the product water from the electrodialysis unit and can be used directly for boiler water makeup. The value of the product water is probably higher than $1.00/1000 gals assumed for the calculations. Although we have not considered it, costs could be reduced by using brine concentration in conjunction with electrodialysis.

TABLE 4-10 OPERATING COST OF TREATMENT AND DISPOSAL SYSTEMS IN THOUSANDS OF DOLLARS PER YEAR

N = 2.5 Cycles of Concentration

	Lurgi			Synthane			Electric Generation		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	346	372	322	558	588	610	2,362	2,488	2,580
Case II	783	785	654	1,247	1,240	1,223	5,597	5,462	5,334
Case III	2,225	1,879	1,317	3,598	2,998	2,487	18,820	15,481	12,729
Case IV	346	372	322	558	588	610	2,362	2,488	2,580
Case V									
Without credit for recycle	811	812	679	1,286	1,277	1,263	5,783	5,658	5,537
With credit for recycle	191	148	103	289	221	169	1,570	1,218	927
Case VI									
Without credit for recycle	3,800	4,060	3,508	6,130	6,448	6,658	27,246	28,534	29,490
With credit for recycle	3,139	3,352	2,894	5,066	5,323	5,492	22,752	23,798	24,573

(Continued)

TABLE 4-10(concluded)

N = 10 Cycles of Concentration

	Lurgi			Synthane			Electric Generation		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	125	135	117	202	213	221	839	882	913
Case II	206	213	180	328	332	332	1,399	1,394	1,393
Case III	437	385	281	707	613	532	3,014	3,036	2,593
Case IV	125	135	117	202	213	221	839	882	913
Case V									
Without credit for recycle	214	223	188	328	348	344	1,436	1,431	1,429
With credit for recycle	111	112	92	162	172	162	734	691	661
Case VI									
Without credit for recycle	700	750	649	1,131	1,190	1,229	4,985	5,221	5,621
With credit for recycle	590	632	547	954	1,003	1,035	4,236	4,432	4,802

TABLE 4-11 AMORTIZATION AND OPERATING COSTS OF TREATMENT AND DISPOSAL SYSTEMS IN THOUSANDS OF DOLLARS PER YEAR

N = 2.5 Cycles of Concentration

	Lurgi			Synthane			Electric Generation		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	346	372	322	558	588	610	2,362	2,488	2,580
Case II	1,335	1,245	988	2,103	1,962	1,818	9,993	9,051	8,258
Case III	6,733	5,495	3,705	10,894	8,749	6,992	58,319	46,664	37,087
Case IV	346	372	322	558	588	610	2,362	2,488	2,580
Case V									
Without credit for recycle	1,431	1,337	1,076	2,234	2,087	1,953	10,626	9,717	8,950
With credit for recycle	811	673	500	1,237	1,031	859	6,413	5,277	4,340
Case VI									
Without credit for recycle	5,488	5,825	5,007	8,855	9,250	9,502	42,049	43,714	44,934
With credit for recycle	4,827	5,117	4,393	7,791	8,124	8,336	37,555	38,978	40,017

(Continued)

TABLE 4-11 (Concluded)

N = 10 Cycles of Concentration

	Lurgi			Synthane			Electric Generation		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	150	162	140	241	255	265	963	1,008	1,041
Case II	342	338	278	534	517	496	2,305	2,160	2,057
Case III	1,208	1,011	699	1,958	1,614	1,321	9,696	8,332	6,752
Case IV	147	159	138	237	250	260	938	981	1,013
Case V									
Without credit for recycle	370	370	305	557	560	536	2,431	2,286	2,180
With credit for recycle	267	259	209	391	383	354	1,728	1,546	1,412
Case VI									
Without credit for recycle	1,005	1,071	922	1,625	1,700	1,747	7,576	7,877	8,859
With credit for recycle	896	953	820	1,448	1,512	1,553	6,827	7,088	8,040

For gasification the waste disposal costs (Table 4-12) range from about 0.45¢/10^6 Btu to 14.1¢/10^6 Btu at low cycles of concentration, and from 0.18¢/10^6 Btu to 2.53¢/10^6 Btu at high cycles of concentration; for steam electric power generation the costs range from 0.40 mils/kw-hr to 9.5 mils/kw-hr at low cycles of concentration and 0.15 mils/kw-hr to 1.6 mils/kw-hr at high cycles of concentration. As a basis of comparison, the cost of pipeline gas is estimated to be about 300¢/10^6 Btu, while electricity costs about 20-30 mils/kw-hr.

The total amortization and operating costs for blowdown treatment and disposal have also been normalized with respect to the flow rate of the blowdown. The results of these calculations are shown in Table 4-13. Across all processes, the costs range from $0.50/1000 gals of blowdown to $12.50/1000 gals of blowdown at low cycles of concentration and $1.20/1000 gals of blowdown to $12.50/1000 gals of blowdown at high cycles of concentration. The normalized costs are higher for higher cycles of concentration than for lower cycles because of the differing flow rates. At a given site and for a given number of cycles of concentration, the costs normalized with respect to the blowdown flow rate are relatively insensitive to either pipeline gas production or steam electric power generation for a particular case of blowdown treatment and disposal. The maximum difference occurs for the case of disposal of all of the blowdown into evaporation ponds and is approximately 20 percent between electric generation and the Lurgi process. For a given process the costs are also relatively insensitive to site with a difference of about 40-50¢/1000 gals of blowdown for all cases except for Case III.

REFERENCES (Section 4)

1. Gold, H., et al, "Water Requirements for Steam-Electric Power generation and Synthetic Fuel Plants in the Western United States," EPA Report No. 600/7-77-037, U.S. Environmental Protection Agency, Washington, D.C., April, 1977.

2. Goldstein, D.J. and Yung, D., "Water Conservation and Pollution Control in Coal Conversion Processes," EPA Report No. 600/7-77-065, U.S. Environmental Protection Agency, Research Triangle Park, N.C., January, 1977.

TABLE 4-12 AMORTIZATION AND OPERATING COSTS OF TREATMENT AND DISPOSAL SYSTEMS NORMALIZED WITH RESPECT TO THE PRODUCT ENERGY OUTPUT

	N = 2.5 Cycles of Concentration								
	Lurgi*			Synthane*			Electric Generation**		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	0.45	0.48	0.42	0.72	0.75	0.79	0.39	0.41	0.42
Case II	1.72	1.61	1.27	2.72	2.53	2.35	1.63	1.47	1.35
Case III	8.70	7.10	4.79	14.07	11.30	8.94	9.51	7.61	6.05
Case IV	0.45	0.48	0.42	0.75	0.75	0.79	0.39	0.41	0.42
Case V									
Without credit for recycle	1.85	1.77	1.39	2.89	2.70	2.52	1.73	1.58	1.46
With credit for recycle	1.05	0.87	0.65	1.60	1.33	1.11	1.05	0.86	0.71
Case VI									
Without credit for recycle	7.08	7.52	6.47	11.44	11.95	12.28	6.86	7.13	7.33
With credit for recycle	6.24	6.68	5.68	10.07	10.50	10.77	6.12	6.36	6.53

(Continued)

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*In ¢/10^6 Btu product

**In mils/kw-hr generated = 0.1¢/kw-hr generated

TABLE 4-12 (concluded)

N = 10 Cycles of Concentration

	Lurgi*			Synthane*			Electric Generation**		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	0.19	0.21	0.18	0.31	0.32	0.34	0.16	0.16	0.17
Case II	0.44	0.44	0.36	0.69	0.67	0.64	0.38	0.35	0.33
Case III	1.56	1.30	0.89	2.53	2.09	1.71	1.58	1.36	1.10
Case IV	0.19	0.21	0.18	0.31	0.32	0.34	0.15	0.16	0.17
Case V									
Without credit for recycle	0.48	0.48	0.39	0.72	0.72	0.69	0.40	0.37	0.36
With credit for recycle	0.34	0.33	0.27	0.51	0.49	0.46	0.28	0.25	0.23
Case VI									
Without credit for recycle	1.30	1.38	1.19	2.10	2.20	2.26	1.23	1.28	1.44
With credit for recycle	1.16	1.23	1.06	1.91	1.95	1.98	1.11	1.16	1.31

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*In ¢/10^6 Btu product

**In mils/kw-hr generated = 0.1¢/kw-hr generated

TABLE 4- 13 AMORTIZATION AND OPERATING COSTS OF TREATMENT AND DISPOSAL SYSTEMS IN DOLLARS PER THOUSAND GALLONS OF BLOWDOWN

N = 2.5 Cycles of Concentration

	Lurgi			Synthane			Electric Generation		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Case II	1.94	1.69	1.54	1.90	1.67	1.50	2.13	1.83	1.61
Case III	9.78	7.45	5.79	9.83	7.46	5.75	12.42	9.44	7.22
Case IV	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Case V									
Without credit for recycle	2.08	1.81	1.68	2.02	1.78	1.61	2.26	1.97	1.74
With credit for recycle	1.18	0.91	0.78	1.12	0.88	0.71	1.37	1.07	0.85
Case VI									
Without credit for recycle	7.97	7.89	7.82	7.99	7.89	7.82	8.96	8.84	8.75
With credit for recycle	7.01	6.93	6.86	7.03	6.93	6.86	8.04	7.88	7.79

(Continued)

TABLE 4-13 (Concluded)

N = 10 Cycles of Concentration

	Lurgi			Synthane			Electric Generation		
	ND	WYO	NM	ND	WYO	NM	ND	WYO	NM
Case I	1.31	1.32	1.31	1.30	1.30	1.31	1.23	1.22	1.22
Case II	2.99	2.75	2.60	2.89	2.65	2.45	2.95	2.66	2.40
Case III	10.55	8.22	6.54	10.59	8.26	6.52	12.50	10.11	7.89
Case IV	1.28	1.29	1.29	1.28	1.28	1.28	1.20	1.19	1.18
Case V									
Without credit for recycle	3.23	3.01	2.85	3.01	2.87	2.65	3.11	2.77	2.55
With credit for recycle	2.33	2.11	1.95	2.11	1.96	1.78	2.21	1.88	1.65
Case VI									
Without credit for recycle	8.78	8.71	8.62	8.79	8.70	8.63	9.79	9.56	10.35
With credit for recycle	7.83	7.72	7.67	7.83	7.74	7.67	8.73	8.60	9.31

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